BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Progress, LLC	)))))))))))	**JOINT PROPOSED ORDER OF CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, UPSTATE FOREVER, AND NATURAL RESOURCES DEFENSE COUNCIL**

COME NOW Intervenors the South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Sierra Club, Upstate Forever, and Natural Resources Defense Council ("NRDC") (collectively, "CCL et al.") and the Carolinas Clean Energy Business Association ("CCEBA"), pursuant to oral instructions from the Chairman of the Commission, at the conclusion of the Hearing, on May 5, 2021, and hereby file this Proposed Order.

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I. INTRODUCTION

This matter relates to the implementation by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke Energy", "Duke", or "the Companies") of Integrated Resource Planning ("IRP") requirements enacted by the General Assembly in H.3659, also known as the South Carolina Energy Freedom Act ("Act 62"). In brief, we find several deficiencies in the 2020 Integrated Resource Plans of Duke Energy Carolinas, LLC and Duke Progress ("Proposed IRPs") filed by the Companies with this Commission on September 1, 2020, and require that the Companies make a variety of changes to their modeling assumptions and methodologies and to file a modified IRP within sixty (60) days of this Order. The Commission also requires a number of more complex changes to the Companies' methods for preparing an IRP, which the Companies will be required to implement in future IRP filings. This will allow these changes to be implemented in a reasonably timely fashion and also enable Commission and intervenor review of those changes, which is appropriate given the fundamental importance and also the complexity of integrated resource planning.

A. Background on Integrated Resource Planning

Integrated Resource Planning is a structured, transparent process for comparing options to meet electric demand. It was introduced in the electric sector in the 1980s, has been widely adopted across the US, and continues to play a key role today in most states. IRP serves a unique and vital purpose within utility regulation, in that it provides a way to comprehensively and systematically consider the wide array of factors that impact electric system choices. When implemented prudently, IRP can save ratepayers billions of dollars, help regulators understand risk exposure and make decisions that align with their risk preferences, improve environmental outcomes, and facilitate stakeholder buy-in for utility plans, reducing the risk of future cost recovery disallowance. It is a powerful tool but must be implemented carefully to provide these benefits.

Act 62 significantly strengthened the IRP process in South Carolina. Compared to the previous IRP statute, Act 62 includes an expanded and more detailed list of requirements for utility IRP filings. Act 62 also enabled formal Commission review of utility plans via a litigated proceeding, in which the Commission must ultimately accept, reject, or order modifications to the utility's proposal. These statutory changes signal both the heightened importance the South Carolina General Assembly has assigned to IRP and also the critical role assigned to this Commission in reviewing and ruling on proposed utility plans.

As commonly implemented, the IRP process involves five basic steps: (1) forecast future electricity demand; (2) identify the goals and regulatory requirements the process must meet; (3) develop a set of resource portfolios designed to achieve those goals; (4) evaluate those resource portfolios; and (5) identify a preferred resource plan.

B. Notice and Intervention

By letter of October 29, 2020, the Clerk's Office of the Public Service Commission of South Carolina transmitted the Notices of Filing and Hearing and Prefiled Testimony Deadlines ("Notices") in the above-referenced dockets to Duke Energy and instructed Duke Energy to publish the Notices in newspapers of general circulation in the affected areas by December 1, 2020, and provide proof of publication on or before December 15, 2020. The Notices indicated the nature of the proceeding and advised all parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On December 9, 2020, the Companies filed affidavits demonstrating that the Notice was duly published in accordance with the instructions set forth in the October 29, 2020 letter.

In Docket No. 2019-224-E, Petitions to Intervene were received from the South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Sierra Club, Upstate Forever, and Natural Resources Defense Council ("NRDC") (collectively, "CCL et al."); the Carolinas Clean Energy Business Association ("CCEBA")[1]; Johnson Development Associates, Inc. ("JDA"); Cherokee County Cogeneration Partners, LLC; Vote Solar; Nucor Steel, and the South Carolina Department of Consumer Affairs ("SCDCA"). The Petitions to Intervene of CCL et al., Cherokee County Cogeneration Partners, JDA, Vote Solar, Nucor Steel, and SCDCA were not opposed by the Companies and no other parties sought to intervene in this proceeding. CCL et al., CCEBA, JDA, Vote Solar, and SCDCA also intervened in Docket No. 2019-225-E. The South Carolina Office of Regulatory Staff ("ORS") is automatically a party to both dockets pursuant to S.C. Code Ann. § 58-4-10(B) (2015).

II. REQUIREMENTS FOR INTEGRATED RESOURCE PLANNING UNDER ACT 62

Act 62, as codified in S.C. Code § 58-37-40, sets forth procedural and substantive requirements for utility IRP filings along with the standard of review for the Commission's review of utility IRPs.

[1] CCEBA was preceded as an intervenor by the South Carolina Solar Business Alliance ("SCSBA"). By later order of the Commission, CCEBA was substituted as a party in interest for SCSBA in this and other dockets.

A. <u>Procedural Requirements</u>

Regulated electric utilities in South Carolina must prepare and submit IRPs with the Commission at least every three years. S.C. Code Ann. § 58-37-40(A). The Commission is required to establish a proceeding to review each utility's IRP in which interested parties may intervene and conduct discovery for the purpose of "obtaining evidence concerning the [IRP], including the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties." S.C. Code Ann. § 58-37-40 (C)(1).

Within 300 days of the IRP being filed, the Commission must issue a final order approving, modifying, or denying the plan. *Id.* If the Commission modifies or rejects a utility's IRP, the utility has 60 days from the date of the final order to submit a revised plan to the Commission. S.C. Code Ann. § 58-37-40(C)(3). Within 60 days after the utility makes its revised filing, ORS must review the electrical utility's revised plan and submit a report to the Commission assessing the sufficiency of the revised filing; other parties to the IRP proceeding also may submit comments. *Id.* Within 60 days after the ORS report is filed, the Commission at its discretion may determine whether to accept the revised IRP or to mandate further remedies as it deems appropriate. *Id.*

Act 62 also establishes that utilities must file annual IRP updates before the Commission. S.C. Code Ann. §58-37-40(D).

B. <u>Required Elements of Utility IRPs</u>

S.C. Code Ann. § 58-37-40(B)(1) states that utility IRPs *must* include the following elements:

(a) A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;

(b) The type of generation technology proposed for any generation facility contained in the plan and its proposed capacity, including fuel cost sensitivities under various reasonable scenarios;

(c) Projected energy purchased or produced by the utility from a renewable energy resource;

(d) A summary of electrical transmission investments planned by the utility;

(e) Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency (EE), and demand response (DR) measures, including consideration of:

   i. customer energy efficiency and demand response programs;

   ii. facility retirement assumptions; and

   iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;

(f) Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;

(g) Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;

(h) An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and

(i) A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction. S.C. Code § 58-37-40(B)(1).

In addition, S.C. Code Ann. § 58-37-40(B)(2) states that IRPs may include distribution resource plans or integrated system operation plans.

C. Standard of Proof

The Commission is directed to approve a utility's IRP if it finds that "the proposed integrated resource plan represents the *most reasonable and prudent* means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." S.C. Code Ann. §58-37-40(C)(2) (emphasis added). To determine whether this standard was met, the Commission is directed to consider, in its discretion, whether the IRP appropriately balances the following seven factors:

(a) Resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;

(b) Consumer affordability and least cost;

(c) Compliance with applicable state and federal environmental regulations;

(d) Power supply reliability;

(e) Commodity price risks;

(f) Diversity of generation supply; and

(g) Other foreseeable conditions the Commission determines to be for the public interest.

The Commission has previously expounded on this standard in its final Order rejecting the Dominion Energy South Carolina 2020 IRP. Order No. 2020-832 at 7 ("As part of its review, the Commission also provides guidance on its interpretation and expectations for compliance with the statute for the public interest not only for DESC, but also for other electrical utilities.") A utility's plan must be "reasonable," meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices. Id. at 12-13. The plan must also be "prudent," which implies that it gives due consideration to actual and foreseeable future conditions and risks. Such consideration should take into account the relative costs and benefits of avoiding potential future risks, such as regulatory, capital, or fuel risks. Id. Although cost is an important consideration, "reasonableness" and "prudence" do not dictate that the utility simply select the least-cost resource plan given the inherent uncertainty of sensitivity assumptions for future conditions. For example, if two plans have nearly the same expected cost, it may be more reasonable and prudent to select the more expensive of the two, if consideration of the other statutory factors (e.g. commodity price risk or diversity of generation) strongly favors that plan. Id.

The Commission's decision must be based on the facts in the record before it; this means that the IRP and the record must provide sufficient information about each of the seven balancing factors such that the Commission can determine if the IRP appropriately balances each of them. Finally, Act 62 provides that the Commission may not approve a utility IRP that is merely reasonable and prudent; the plan must represent the *most* reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed. This standard implies that IRP requirements should not be static, but rather should continuously improve over time as standards and practices improve and evolve. It also implies that a utility may not do the bare minimum, but rather must ensure that its IRP is the result of serious planning and consideration using the best available data and tools available to it.

Inherent in this standard is the requirement that a utility's IRP include a "plan." According to Merriam-Webster, a "plan" is a "method of achieving an end" or a "detailed formulation of a program of action."[2] While a utility's plans may change over time, and an IRP does not substitute for Commission approval of any specific expenditure or resource decision, the purpose of an IRP is for a utility to fairly evaluate the range of resource options available to it and identify and explain the course of action it intends to take. In the context of an IRP, this means the utility must (1) identify a preferred portfolio from the range of portfolios analyzed and (2) include a short-term action plan that identifies steps the utility will take to achieve that preferred portfolio.

D. Requirement to Select a Preferred Plan

One issue of contention between the parties is a question of law, namely, whether Act 62 requires the utility to select a plan for meeting its resource needs over the planning period.

The Companies' IRPs present a suite of six resource portfolios (described further below) without selecting a single one as the preferred resource portfolio. CCEBA, in the testimony of Witness Kevin Lucas, took the position that the Companies' IRPs are deficient because of Duke's failure to select a preferred resource plan. (Tr. p. 501.17:10-19.) He

[2] Merriam Webster, "Plan", https://www.merriam-webster.com/dictionary/plan.

stated that selecting a particular portfolio was necessary for the Commission to determine whether Duke's IRPs constituted the most reasonable and prudent means of meeting the utilities' resource needs. (*Id.*)

On behalf of the Companies, Duke Energy Witness Glen Snider testified that in his (non-legal) opinion Act 62 does not require the Companies to pick a single preferred long-term resource planning portfolio. Witness Snider stated that the Companies "presented their IRPs as a total plan that can adapt to changing standards, technology and policy decisions in the future." (Tr. p. 1586.41:12-14.) At the hearing, he stated that, in his view, Act 62 does not require the utility or the Commission to pick a resource portfolio within the IRP, but rather, to decide whether the plan in its totality is the most reasonable and prudent. (Tr. p. 1709:15-19.) Mr. Snider testified that "there are a couple of portfolios that are more likely to be used by the Commission in future proceedings as they adjudicate issues before them." (Tr. at 1709:20-22.)

However, Witness Snider testified that the Companies consider the Base Case without Carbon resource plan to be the "most appropriate plan" at this time and intend to use that same portfolio in its avoided cost and DSM proceedings. (Tr. p. 1586.43:5-11; Tr. p. 1608:6-18.) Mr. Snider conceded on cross examination that the Companies would need to take steps in the near term to procure resources for future capacity needs (Tr. p. 1719:14-22), which could vary based on which resource portfolio the Companies pursue.

In surrebuttal, Witness Lucas reiterated his position that Act 62 requires the selection of a preferred resource portfolio. As he testified, the inputs from the Companies' IRPs will be used in a variety of proceedings, and would vary widely depending on the resource portfolio used. (Tr. 1911.12:4-9.) At the hearing, Mr. Lucas further testified that the Companies' IRPs put forth six different portfolios that have six different characteristics, and that the Companies would have to make very different short- and long-term decisions depending on which of those portfolios it chose to pursue. (Tr. at 2042:7- 2044:1.)

The Commission rejects Duke's position and concludes Act 62 requires the Companies to select a single preferred resource portfolio in its IRPs. As the Commission indicated in Order 2020-832 rejecting the 2020 DESC IRP, the identification of a preferred resource plan is an essential step in the development of an IRP. *See* Order 2020-832 at 18.

The six portfolios presented in Duke's IRPs are dramatically different from each other; without an indication of which portfolio or combination of portfolios Duke intends to pursue, the Commission would have to conclude that *any* of these portfolios, or combinations thereof, would constitute "the most reasonable and prudent means" of meeting Duke's resource needs. There is simply no evidence in the record for the Commission to make such a sweeping conclusion. Duke itself provided in discovery, and acknowledged in testimony, that it deemed its Base Case without Carbon resource plan to be the "most appropriate" resource plan for almost all planning purposes; if Duke intends to pursue this plan, it must disclose that decision to the Commission and stakeholders.[3]

The Companies will be making a variety of resource decisions over both the short-term and long-term; those decisions—though they could change over time—should be reflected in the Companies' preferred portfolio. Further, the Companies' IRP will serve as an input into a variety of other proceedings. Those inputs vary widely depending on which

[3] Although Mr. Snider took the position that the utility was not required by Act 62 to select a resource plan, he acknowledged that the portfolio designated as the "Base plan" in the IRP was the "selected plan" referred to in the update provision Act 62 (S.C. Code Ann. § 58-37-40(D)(1)). (Tr. p. 1615:7 – 1615:25, 1617:15 - 21.)

portfolio is at issue. Witness Snider's position that different portfolios may be appropriate for the Commission to use in different proceedings simply does not make sense in light of the fact that the Companies, ultimately, can and will actually operate under only one portfolio of resources. It is not a tenable position to hold that the Companies could, on the one hand, pursue the Small Modular Nuclear Reactors anticipated in the No New Gas portfolio while at the same time pursuing actions set out in the Base Case with No Carbon and claim that they were acting under the same approved "plan."

While the Companies may change their planned course of action over time in response to changes in circumstances, the Commission's role is to determine whether or not the Companies' preferred plan is the most reasonable and prudent means of meeting the Companies' resource needs as of the time the IRP is reviewed.

The Commission is persuaded that a utility's plan must include which portfolio it intends to pursue. Each of the six resource portfolios in the Companies' IRPs was designed to meet the utilities' expected resource needs; in other words, each portfolio is a distinct "means of meeting the electrical utility's energy and capacity needs." S.C. Code Ann. § 58-37-40(C)(2). It stands to reason that Act 62 requires that the utility select a preferred resource portfolio in its IRP, and that the Commission must determine whether that chosen portfolio represents the most reasonable and prudent means of meeting the utilities' resource needs as of the time the plan is reviewed.

As a result, the Commission finds that the Companies' 2020 IRPs are deficient due to the Companies' failure to select a preferred portfolio. After updating its modeling assumptions in accordance with the other directives of this Order, the Companies are directed to select a preferred resource portfolio in their Modified 2020 IRPs.

E. Integrated resource planning and ratepayer risk

Consistent with the purposes of Act 62 and other sections of the Act,[4] The IRP provisions of Act 62 include requirements intended to identify and mitigate potential risks to ratepayers. IRPs must include multiple resource portfolios evaluated under "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." S.C. Code Ann. § 58-37-40(B)(1)(e)(iii). For these various sensitivity analyses, the Act also specifies the required use of "reasonable scenarios." S.C. Code Ann. 58-37-40(B)(1)(b).

Furthermore, in determining whether an integrated resource plan is the most reasonable and prudent means of meeting a utility's energy and capacity needs, Act 62 requires that the Commission balance a number of factors, including "commodity price risks" and "diversity of generation supply" S.C. Code Ann. 58-37-40(C)(2)(e) and (f).

F. Evidentiary Review

In reviewing the testimony in this case, the Commission notes that certain parties – in particular Duke Energy – have attempted to discredit the testimony and evidence submitted by other parties, alleging they are biased towards certain outcomes, in particular protecting public health and the environment, and promoting clean energy. The Commission notes that the goals of the parties in this matter are various, and in the case of Duke Energy in particular they are compound, including regulatory obligations to Duke's customers and fiduciary duties to Duke's shareholders. Rather than delve into such goals, the Commission instead will focus its review on the evidence in the record regarding the substantive issues at hand, applying the standards of review summarized above.

[4] Cf. S.C. Code Ann. § 58-41-20(A).

III. HEARING

In order to consider the merits of these cases, the Commission convened a consolidated hearing on these matters from April 26 to May 6, 2021, with the Honorable Justin T. Williams presiding. Duke Energy was represented by E. Brett Breitschwerdt, Esquire; Frank R. Ellerbe, Esquire; and Rebecca J. Dulin, Esquire. CCL et al. were represented by Kate Lee Mixson, Esquire and Gudrun E. Thompson, Esquire. CCEBA was represented by Benjamin L. Snowden, Esquire; John D. Burns, Esquire; and Richard L. Whitt, Esquire. JDA was represented by Weston Adams, III, Esquire and Courtney E. Walsh, Esquire. Jeffrey M. Nelson, Esquire, and Andrew M. Bateman, Esquire represented ORS. Cherokee County Cogeneration Partners, LLC, Nucor Steel, and SCDCA were excused from the hearing and did not appear. In this Order, ORS, CCL et al., CCEBA, JDA and Duke Energy are collectively referred to as the "Parties" or sometimes individually as a "Party."

Duke Energy presented the direct testimonies and exhibits of Glen Snider, Dewey S. ("Sammy") Roberts II, Leon Brunson, Matthew Kalemba, Dawn Santoianni, Nick Wintermantel, and Brian Bak. CCL et al. presented the direct testimony and exhibits of Jim Grevatt and James Wilson. ORS presented the direct testimonies and exhibits of Anthony M. Sandonato, Philip Hayet, Stephen J. Baron, and Lane Kollen. Vote Solar presented the direct testimony and exhibits of Tyler Fitch. CCEBA presented the direct testimony and exhibits of Kevin Lucas and Arne Olson. JDA did not present witnesses at the hearing. In response to the direct testimony filed by intervenors, Duke Energy presented the rebuttal testimony and exhibits of Witnesses Snider, Brunson, Kalemba, Santoianni, Wintermantel, Roberts, Bak, Mark Oliver, and Jim Herndon. In response to Duke Energy's rebuttal testimony, CCEBA filed surrebuttal testimony of Witnesses Lucas and Olson; CCL et al. filed surrebuttal testimony of Witnesses Grevatt, James Wilson, and John Wilson; CCL et al. and CCEBA jointly sponsored surrebuttal testimony from Rachel Wilson; Vote Solar filed surrebuttal testimony of Witness Fitch; and ORS filed surrebuttal testimony of Witnesses Sandonato, Hayet, Baron, and Kollen.

IV. FINDINGS OF FACT

Load Forecast and Demand Side Management/Energy Efficiency ("DSM/EE")

1. The Companies' consideration of only near term growth and recession scenarios in its load forecast analysis does not satisfy Act 62's requirement for an IRP to consider "a long-term forecast of the utility's sales and peak demand under various reasonable scenarios." S.C. Code Ann. § 58-37-40(B)(1)(a). Act 62 requires an analysis of load forecast that considers a higher degree of uncertainty with regard to long-term peak loads.
2. It was unreasonable for the Companies, and their consultant Nexant, to use the TRC in developing EE/DSM scenarios and savings projections in the 2020 IRPs. In future IRPs, IRP updates, and market potential studies, the Companies must use the UCT to determine achievable potential.
3. The Companies' failure to consider how increased market acceptance and emerging technologies could increase energy efficiency and demand side management savings resulted in an underestimation of achievable potential in Duke territories. Relatedly, it was unreasonable for the Companies to limit the participation rates to historic levels in its Base scenario in the market potential studies.

4. The residential savings projections in Companies' market potential studies were overly dependent on behavioral programs with short savings persistence. The Companies should develop a more balanced residential savings portfolio in the future that incorporates more longer lived measures that do not require yearly expenditure to produce savings.

Resource Adequacy and Planning Reserve Margin

Winter Resource Adequacy

5. It is reasonable to require the Companies, prior to filing future IRPs, to study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load for use in future IRP proceedings.

Capacity Value of Solar and Storage

6. Duke failed to capture the synergistic effects of solar and storage by calculating their capacity values separately and modeling them sequentially rather than simultaneously. Duke's analytical errors prevented these resources from competing on equal footing with resources like gas.
7. Duke's failure to model battery storage in preserve reliability mode improperly discounted that resource's capacity value and inaccurately prejudiced the ability of storage to compete in modeling against other resources.
8. Duke's assumption that only 40% of new solar would feature single-axis tracking does not accurately reflect the reality on Duke's system, was not reasonable, and had the effect of prejudicing solar by underestimating the capacity and energy benefits that tracking provides.

9. Duke's use of the installed capacity ("ICAP") method for determining production reserve margin while using the Effective Load Carrying Capability ("ELCC") method for determining the capacity value of solar and storage disadvantaged those resources by arbitrarily and inaccurately discounting their capacity value. Duke should instead use the unforced capacity ("UCAP") method.
10. Because growing load increases a resource's load-carrying capability as the resource provides a smaller percentage of total capacity, Duke's use of 2024 load rather than higher loads predicted by the IRP improperly discounted the capacity value of solar.
11. A system's generation mix plays a large role in the net load that must be served and the seasonality of loss of load events, such that a winter peaking system can still have capacity constraints in the summer and vice versa. Those dynamics are properly represented using an annual ELCC value that takes into account the capacity contribution of resources in both the summer and the winter.

Coal Retirement Analysis

12. It is reasonable for this Commission to require Duke to conduct a new analysis to determine the most economic retirement dates for the combined DEC and DEP fleet of coal plants, as well as the resources that should replace them. Accordingly, it is reasonable to require the Companies to perform a comprehensive coal retirement analysis to inform development of their 2022 IRPs, solicit parties' recommendations on guidelines for performing this analysis via the ongoing IRP stakeholder process, and adopt a set of guidelines prior to development of the 2022 IRPs.

Modeling Assumptions and Inputs

Natural Gas Forecasting

13. Duke's Natural Gas Forecasting Methodology is fundamentally flawed and results in generation mixes which do not represent the most reasonable and prudent means of meeting Duke's energy and capacity needs.

14. Duke fails to account for risks to natural gas delivery for its CC units, adding gigawatts of new units without firm supply. Given the risks associated with natural gas delivery over the long term, it is unreasonable for Duke to assume firm fuel transport for natural gas CC units at the same price as is currently available.

15. Duke's Natural Gas pricing forecasts rely too heavily and for too long on forward contract prices determined at a market low point and maintained for over 10 years in the forecast period. This methodology commits the Companies to large-scale buildouts of natural gas generation assets, at the expense of renewables and storage, endangering the Companies' internal commitment to net-zero generation by 2035.

Solar/Storage Power Purchase Agreement ("PPA") Cost Assumptions

16. Procurement of solar energy-only resources through competitive procurement may lead to ratepayer savings, and it is reasonable to include competitively-procured resources as a selectable resource option in the IRP.

17. It was unreasonable for Duke not to include in its IRP a generic solar resource option reflecting the actual expected cost of procuring solar resources in its service territories.

18. $38 / MWh represents a reasonable proxy for the price of third-party solar resources that could be obtained by Duke through competitive procurement.

Solar Operational Assumptions

19. In modeling solar deployment in its resource plans, it is appropriate for Duke to acknowledge the amendment of the Federal Investment Tax Credit. It is reasonable to require Duke to re-run its IRP modeling taking the ITC into account.
20. In modeling the performance of solar in its IRP, it is appropriate for Duke to model increasing installation of single-axis tracking systems. It is reasonable to require Duke to re-run its IRP modeling to take the increased prevalence of single-axis tracking systems into account.

Battery Storage Pricing

21. In modeling the costs of its candidate resource plans it is appropriate for Duke to use the NREL ATB Low figures for battery storage. It is reasonable to require Duke to re-run its IRP modeling using the NREL ATB Low figures.
22. Duke's 500 MW annual limitation on the interconnection of renewable generation and storage resources in the base cases, without regard to improvements to interconnection capacity or Duke's documented history of interconnecting higher amounts of solar, is unreasonable and discriminatory. This limitation has the potential to artificially constrain the amount of renewables and storage that can be selected by the model, without imposing similar constraints on non-renewable resources.
23. Duke has interconnected significantly greater amounts of generation in prior years, and also models the interconnection of up to 900 MW per year of renewables in certain portfolios.

24. It is reasonable to require Duke to adopt a 750 MW annual interconnection limitation in a Modified IRP and IRP Update, and to require Duke to provide an analytically justified and nondiscriminatory limitation to be presented in future IRPs.

Risk Assessment and Plan Evaluation

Risk Methodology and Application of Minimax Regrets Analysis

25. It is appropriate for DEC and DEP to perform a minimax regret analysis to compare the risk of candidate resource plans. This is consistent with Act 62's requirement that the utilities consider commodity price risk and diversity of generation supply. It is appropriate for Duke to use the minimax regret analysis methodology used and described by CCEBA Witness Lucas in his direct and rebuttal testimony. It is also appropriate for Duke to conduct this analysis beginning in its Modified IRP using updated inputs consistent with the Commission's other findings of fact in this Order.

Evaluation of Stranded Asset and Climate Risks

26. The Companies' 2020 IRPs are inconsistent with Duke Energy's 2050 net-zero carbon goal and do not adequately address climate risks or the regulatory risks of carbon policies that are likely in the future, including the substantial risk to ratepayers of potential stranded asset risks.

Synapse Report

27. The evidence shows that a resource portfolio that accelerates coal retirements, restricts new gas additions and maximizes clean energy resources on the DEC and DEP systems can maintain reliability while minimizing costs to ratepayers. It is

therefore reasonable for this Commission to require the Companies to model a scenario that employs the assumptions used in Synapse's Reasonable Assumptions scenario, and to include the results in modified IRPs to be filed within 60 days of the Commission's order in these proceedings.

All Source Procurement

28. In developing their 2020 IRPs, Duke relied on assumptions regarding resource costs and availability that will be outdated by the time those resources are procured. This approach could lead the Companies to procure a resource mix that is unnecessarily costly for ratepayers. It is therefore reasonable to require DEC and DEP to develop plans to implement all-source procurement, pursuant to the approach described in Exhibit JDW-2 to CCL et al. Witness John Wilson's surrebuttal testimony (H.E. 53) and to include such plans in their 2022 and later IRPs and IRP Updates. Because most resources identified in the short-term action plans in Duke's IRPs are already approved or otherwise committed for construction or procurement, it is reasonable to require DEC and DEP to plan for implementation of all-source procurement beginning in 2026.

V. <u>REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS</u>

A. <u>Summary of Duke's IRP</u>

Duke Witness Glen Snider sponsored the Companies' 2020 IRPs and presented direct testimony summarizing the information presented in the planning document. (Tr. p. 62.5:1-17.) The IRPs present the same six long-term resource planning portfolios, each designed to meet the forecasted electricity requirements, including a reserve margin of 17%, over the next 15 years:

1. Portfolio A, the "Base without Carbon Policy" portfolio, was developed as a least cost plan under current regulations and with reliance on available technologies. (Tr. p. 57:21-24.) It relies on new gas generation to meet load growth and replace retiring capacity and retires coal units on the "most economic" dates. This portfolio does not select additional solar beyond the base case forecast, which brings the Companies' total solar capacity to 8 GW by the end of the IRPs' planning horizon in 2035. (Tr. p. 62.15.)
2. Portfolio B, the "Base with Carbon Policy" portfolio, was developed using the same assumptions as Portfolio A but incorporates a base carbon tax policy as a proxy for future carbon legislation. As a result, and though this plan continues to rely heavily on natural gas capacity to meet future load growth, additional renewable resources are also selected as an economical way to meet demand. Ultimately, 1,400 MW more incremental solar plus storage is selected in this portfolio as compared to Portfolio A. Portfolio B also retires coal units on the "most economic" retirement dates. (Tr. p. 62.16; H.E. 1 p. 95.)
3. Portfolio C, the "Earliest Practicable Coal Retirements" portfolio, seeks to retire existing coal units at the "earliest practicable" date, as opposed to pursuing only "least cost" planning criteria. The plan retires all coal units by 2030 and leverages existing infrastructure to eliminate the need for transmission upgrades at the retiring coal sites. Like Portfolio B, the plan relies on batteries and the addition of solar and wind to meet future demand. (Tr. p. 62.17; H.E. 1 p. 95.)

4. Portfolio D, the "70% CO_2 Reduction: High Wind" portfolio, sets out a path for the Carolinas to reduce CO_2 emissions 70% by 2030. This portfolio builds on Portfolio C, using the "earliest practicable" coat retirement dates, but adds additional renewable resource capacity with a focus on offshore wind. Under this portfolio, the Companies add 4 GW more solar than Portfolio B, 2.6 GW of offshore wind, 2.8 GW of onshore wind, and 4.4 GW of energy storage. In addition, this portfolio sets high savings levels for energy efficiency and demand side management programs to assist in reaching the 70% reduction goal. (Tr. pp. 62.18:5 – 62.19:12.)
5. Portfolio E, the "70% CO_2 Reduction: SMR" portfolio, is essentially the same as Portfolio D in that it relies on additional solar capacity, storage, and energy efficiency and demand side management programs to reduce CO_2 Reduction by 70%. However, instead of adding offshore wind, this portfolio deploys two new small modular nuclear reactor plants to be in service by 2030. (Tr. pp. 62.19:13 – 62.20:20.)
6. Portfolio F, the "No New Gas Generation" portfolio, was designed to evaluate how the Companies could transition the current portfolio to a net-zero carbon portfolio by 2050 without building new gas generation. This portfolio achieves 73% CO_2 Reduction by 2035, using offshore wind, one small modular nuclear reactor, energy storage, and high levels of energy efficiency and demand side management. The "most economic" coal retirement dates were used in this portfolio. (Tr. p. 62.21; H.E. 1 p. 97.)

Each portfolio was evaluated in the IRPs under a range of sensitivities and fuel and carbon prices to test the portfolio's performance under various future scenarios. (H.E. 1 p.

12.) Ultimately, the IRPs identify Portfolio A and B as the lowest cost and most reliable options. (H.E. 1 p. 100.) In a table comparing each of the portfolios in the IRPs, the Companies characterize each resource plan as increasingly dependent on technology and policy advancements, with the Portfolio E and F being the most dependent on those advancements. (H.E. 1 p. 16.) Witness Snider testified that the Companies did not select one preferred portfolio, but rather viewed each IRP as a whole, with all six resource portfolios "present[ing] a total plan that can adapt to changing standards, technology, and policies." (Tr. pp. 60:10-21, 1706 – 07.)

B. Load Forecast and Demand Side Management/Energy Efficiency

1. Load Forecast

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 1

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony and exhibits in these dockets of Duke Witnesses Leon Brunson and Glen Snider, CCL et al. Witness James Wilson, and the entire record in this proceeding.

Duke Witness Leon Brunson performed the load forecast for the DEC and DEP service areas. (Tr. p. 292:10-13.) The models used to develop the load forecasts predict future energy and demand growth and are therefore vital to determining resource adequacy and system reliability needs. (Tr. p. 293:1-11.) Inputs to the models include energy history, weather, electric prices, economic drivers, and federal appliance efficiency trends; additional considerations include rooftop solar, electric vehicles, energy efficiency, and voltage control restraints. (Tr. p. 294:13-19.)

In developing the 2020 IRPs, the Companies relied on the Spring 2020 load forecast, which forecasts customer electricity needs from 2021 to 2035. (Tr. pp. 293:24 – 294:7.) According to Witness Brunson, that forecast predicted an annual residential growth rate of 2.1% for DEC and 1.4% for DEP, both of which are primarily driven by an increasing number of residential customers as opposed to increasing energy usage; commercial and industrial sales are also expected to grow at a slower rate. (Tr. pp. 296 – 97.) Mr. Brunson testified that the DEC and DEP 2020 peak load forecasts had lower peak levels than the 2019 forecast, which he attributed in part to lower 2019 actual peaks, slower economic growth assumptions, and improvements to the load forecasting process. (Tr. p. 293:12-23.) Because the forecast used in the 2020 IRPs was developed in January 2020, the impacts of COVID-19 were not considered. (Tr. p. 294:20-25.) However, Mr. Brunson testified that 2020 demand observations suggest COVID-19's impact on peak demand was relatively insignificant. (Tr. p. 295.)

CCL et al. Witness James Wilson focused his analysis primarily on the Companies' resource adequacy analysis, but also reviewed the Companies' peak load forecasts. (Tr. p. 616.4, n. 6 [James Wilson Direct p. 4, n. 6].) Based on his review, he recommended that the Companies prepare additional load forecast scenarios, such as high and low scenarios, as required by Act 62, S.C. Code Ann. Section 58-37-40(B)(1)(a.) (Tr. p. 616.13:11-15.) In his report, Witness Wilson also observed that, though the Companies' peak load forecasts "appear to fall within a reasonable range," the fact that they were prepared with pre-pandemic economic projections may mean that peak loads in the coming years are slightly lower than predicted. (H.E. 18 p. 9 [James Wilson Exhibit B p. 9.) ORS Witnesses Phillip Hayet and Stephen Baron testified that the Companies' load forecasts were “reasonable,” but recommended that Duke provide a technical appendix showing the equations used to develop load forecasts in future IRPs. (Tr. pp. 888:24 – 889:10, 926:22 – 927:6.)

In rebuttal, Witness Brunson testified that, contrary to Witness Wilson’s testimony, 2020 data has thus far indicated that economic drivers used in the load forecast were “reasonable, if not conservative.” (Tr. p. 302.) Witness Snider also noted in rebuttal that the load forecast “includes scenarios that assume more optimistic conditions and 2 recession-like conditions compared to the base forecast.” (Tr. p. 1586.54:2-3.)

In surrebuttal, Witness Wilson clarified that the “scenarios” referred to by Witness Snider are actually sensitivity analyses that use Moody’s Analytics’ forecasts of near-term and recession scenarios. (Tr. p. 618.2.) Mr. Wilson explained that this analysis fails to account for the high degree of uncertainty in long-term peak load forecasts and does not consider “reasonable scenarios” of future peak load growth as required by Act 62. *Id.* He further observed that the Companies’ load forecast sensitivity analysis, “which appears to suggest very little uncertainty about future peak loads,” is “highly inconsistent” with the Companies’ resource adequacy studies, which assume, based on economic load forecast error alone, that the Companies’ load forecasts may be two percent or more too high or too low with substantial probability. (Tr. p. 618.3.)

Commission Conclusions

The Commission finds based on the evidence that the load forecasts used to prepare the Companies’ 2020 IRPs are reasonable. However, the Commission agrees with Witness Wilson that Act 62 requires a peak load analysis that considers a higher degree of uncertainty with regard to long-term peak loads. The Companies’ consideration of only near-term growth and recession scenarios does not satisfy Act 62's requirement for an IRP to consider "a long-term forecast of the utility's sales and peak demand under various reasonable scenarios." S.C. Code Ann. § 58-37-40(B)(1)(a.) The Companies are therefore directed to prepare additional load forecast scenarios, such as high and low scenarios that account for economic and other types of uncertainty in future IRPs. The Commission is also concerned by Mr. Wilson's testimony that the degree of uncertainty considered in the load forecast is inconsistent with the uncertainty accounted for in the resource adequacy studies given how related these analyses are to each other. In future IRPs, the level of uncertainty reflected in the load forecast analysis should be consistent with the Companies' resource adequacy studies.

2. Energy Efficiency and Demand-Side Management

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 2 - 4

Summary of the Evidence

The evidence in support of these findings of fact is found in the testimony and exhibits in these dockets of Duke Witnesses Brian Bak, Jim Herndon, and Glen Snider, CCL et al. Witness Jim Grevatt, ORS Witness Philip Hayet, and the entire record in this proceeding.

Duke Energy Witness Bak introduced the Companies' current demand side management ("DSM") and energy efficiency ("EE") programs. (Tr. pp. 258.4:20 – 258.5:4.) In the IRPs, EE programs, which improve the energy efficiency of customers to the end of reducing their electricity consumption, were treated as a reduction to the load forecast, while DSM programs, which "prompt customers to reduce electricity use during select peak hours as specific by the Companies," were treated as a "dispatchable" resource that can be used to meet capacity need during period of peak demand. (Tr. p. 258.5:9-17.)

Duke commissioned an EE/DSM Market Potential Study ("MPS"), prepared by consultant Nexant, Inc., to estimate achievable EE/DSM savings under three scenarios. (Tr. p. 258.10.) The "Base" scenario aligned with the Companies' existing EE portfolio and also assumed the Companies' existing DSM incentives would continue to be used. (Tr. pp. 258.12, 258.14.) The "Enhanced" scenario incorporated the Base scenario portfolio but assumed there was increased program spending to attract new customers and that the existing incentive programs for each DSM program would double. (Tr. pp. 258.12, 258.14 – 258.15.) The "Avoided Energy Cost Sensitivity" scenario evaluated the Base scenario assuming that EE benefits were enhanced by avoided energy costs that are higher than current values. (Tr. p. 258.12.)

Nexant used the Total Resource Cost Test ("TRC") to screen the cost-effectiveness of various programs and determine achievable potential. (Tr. p. 258.13:10-11.) The MPS also included a sensitivity to calculate economic potential based on the Utility Cost Test ("UCT"), which "tend[s] to show a higher economic potential than TRC." (Tr. pp. 264:4 – 264:16.) Nexant did not use the UCT screen to estimate achievable potential (Tr. p. 265:10-17), but the Companies attempted to simulate the UCT's tendency to improve economic potential by applying a 10% increase to the achievable potential when developing the High DSM/EE projections in the IRPs. (Tr. pp. 258.13, 265:17-25.) While Witness Bak's prefiled testimony stated that the Companies only applied this 10% adjustment to the Enhanced scenario, which was used to develop the High EE/DSM case, at the hearing Mr. Bak stated that the Companies made this adjustment to the MPS in every scenario.

(*Compare* Tr. p. 258.13:18-21 *with* Tr. p. 1244:9-12.) As such, it is unclear to which scenarios the Companies applied the 10% increase to adjust for increased potential under UCT versus TRC.

The achievable potential estimates in the MPS were incorporated into the IRPs "by blending the Companies' respective five-year program planning forecast into the long-term achievable potential projections from the [MPS]." (Tr. p. 258.11:3-5.) Using this approach, the Companies developed three sets of projections to evaluate the various resource portfolios in the IRPs: (1) a Base EE Portfolio savings projection, which incorporated the Base scenario from the MPS; (2) a High EE Portfolio savings projection based on the Enhanced and Avoided Energy Cost Sensitivity scenarios contained in the MPS; and (3) a Low EE Portfolio savings projection developed by applying a reduction factor across all measures in the Base EE Portfolio as a way to forecast lower than expected adoption of all measures. (Tr. p. 258.11:9-20; *see also* H.E. 1 (Snider Direct Exhibit 1 at pp. 35 – 36).)

CCL et al. Witness Jim Grevatt testified that the MPS used by the Companies to develop its IRPs significantly underestimated potential EE and DSM savings in Duke's territory. (Tr. p. 667.4; *see also* H.E. 19 [Grevatt Direct Ex. B].) Witness Grevatt first questioned Nexant's decision to use the TRC rather than the UCT to screen for program cost-effectiveness, even though the UCT is a more relevant measure of cost-effectiveness for use in utility planning and has been approved by the Commission as the primary cost-effectiveness test for Duke. (Tr. pp. 667.10, 667.13.) While the UCT accounts for how EE and DSM can reduce utility system costs, which is the appropriate consideration in an IRP proceeding, the TRC tends to understate cost-effectiveness, making EE and DSM resources seem misleadingly expensive when compared with other resource options. (Tr. p. 667.13.)

Next, Witness Grevatt testified that the MPS unreasonably limited its consideration of programs to existing measures and technologies and historic participation rates, failing to account for the likelihood of new technologies to emerge and to decrease in cost as they continue to develop market acceptance. (Tr. pp. 667.8 – 667.9.) In addition, by calibrating achievable potential to historic participation rates, the MPS failed to consider that participation rates can be improved by a variety of factors, including incentives, marketing, and improved program delivery. (Tr. p. 667.9.) Mr. Grevatt also expressed concern that the MPS's residential savings were overly dependent on behavioral programs, which have very short savings persistence and have been found to be more expensive than longer-lived measures, such as HVAC equipment that can save energy for decades after it is installed. (Tr. pp. 667.12:11 – 667.13:3.)

Lastly, Witness Grevatt highlighted Nexant's underestimation of DSM potential at times of winter peak demand. Duke's Winter Peak Analysis, which evaluated several innovative approaches that the MPS excluded, identified in its "Max" scenario nearly twice the winter peak potential identified in the MPS's "Base" scenario. (Tr. p. 667.14)

ORS Witness Phillip Hayet submitted testimony relating to the Low, Base, and High EE/DSM Portfolios in the IRPs. First, Witness Hayet questioned why the Companies incorporated the Base EE/DSM Portfolio in Portfolio A even though the sensitivity cases with the High EE/DSM Portfolio were lower cost. (Tr. p. 856.12.) Next, Mr. Hayet recommended that the Companies evaluate High and Low EE/DSM projections across different fuel/CO_2 scenarios rather than merely considering resource portfolios that assume different levels of EE/DSM across various fuel/CO_2 forecasts. (Tr. p. 856.13:1-7.) Lastly, Mr. Hayet requested that the Companies provide some justification for the percentage reduction applied to the Base scenario to derive the Low EE/DSM projections. (Tr. p. 856.13:8-15.)

In rebuttal, Witness Bak responded to Witness Grevatt's testimony, emphasizing that the MPS should "reflect *actual* energy and demand reduction potential," as in "known and quantifiable energy and demand savings, actually achievable by DEC and DEP," and not "serve as a brainstorming exercise for program designs." (Tr. p. 1213.3 (emphasis in original).) Mr. Bak suggested that consideration of emerging EE/DSM technologies or market trends could compromise the Companies' ability to meet customer load. (Tr. pp. 1202:14 – 1203:5, 1213.5.) However, at the hearing, Mr. Bak acknowledged that the MPS and the IRPs do in fact rely on estimates of potential EE/DSM savings that are not yet "known and quantifiable." He first agreed that the MPS does not and cannot reflect verified savings because it looks at future potential. (Tr. p. 1242:11-23.) Mr. Bak next acknowledged that the 10% increase used to simulate economic potential under the UCT was "an estimate and not verified by the MPS," but nevertheless a reasonable assumption. (Tr. pp. 1245:3-7, 1248:1-5.) Mr. Bak further testified that the IRPs reduced load forecast by amounts derived using that 10% estimate. (Tr. p. 1245:8-18.)

Witness Bak also highlighted several challenges preventing the Companies from increasing EE/DSM savings, noting that "market acceptance" of EE measures could lower costs but also decrease those measures' effectiveness due to free ridership, (Tr. pp. 1213.17 – 1213.18), and that the potential tightening of efficiency codes and standards posed a "significant challenge" to achieving greater EE/DSM savings, (Tr. p. 1213.10:3-9.) At the hearing, however, Mr.Bak testified that widespread market acceptance could "drive a lot of energy efficiency savings particularly if each unit installed provides savings," (Tr. pp.

1234:4-8), and that it is possible for utilities to achieve greater savings levels than those identified in an MPS, (Tr. p. 1238:7-11.)

Duke Energy Witness Jim Herndon, who is employed by Nexant and was responsible for preparing the MPS, also submitted rebuttal testimony in which he characterized Witness Grevatt's suggestion to consider "emerging technologies" and "unspecified 'technology improvements'" as overly speculative. (Tr. pp. 990:4-7, 992:20 – 993:5; Tr. pp. 1000.5:11 –1000.6:6.) Witness Herndon also dismissed Mr. Grevatt's concern relating to the reliance on behavioral programs to achieve residential savings in the MPS, claiming that Mr.Grevatt "conflate[ed]" measure life and savings persistence and that the one-year measure life of behavioral programs in the MPS was used merely for the purpose of cost-effectiveness testing. (Tr. p. 1000.10.) At the hearing, however, Mr. Herndon clarified that the one-year measure life used for behavioral programs was not merely for cost-effectiveness testing but was used because one year is the length of time measure savings persist with the expenditures required to offer those programs. (Tr. pp. 1017:15 – 1018:1.) In other words, as Mr. Herndon stated, "if you stop the programs, yes, the savings would go away." (Tr. p. 1014:10-11.) In contrast, Mr. Herndon agreed that other non-behavioral measures like heat pumps, duct sealing, and insulation, generate savings that persist for longer than one year without additional spending. (Tr. p. 1018:2-9.)

Witness Herndon next defended the use of the TRC in the MPS to determine achievable potential, testifying that Nexant used the TRC to align with the "regulatory structure" in place at the time of the study but also because "the TRC includes consideration of customer economics whereas…the UCT…only looks at the utility perspective." (Tr.

1002:9-23.) Mr. Herndon agreed, though, that the UCT was "appropriate" for program planning because it is from the utility's perspective. (Tr. p. 1004.)

Duke Witness Glen Snider responded to ORS Witness Hayet's recommendations, noting that it was "premature" to count on the High EE/DSM projections and that the Companies would move the High EE/DSM projections into Portfolio A if additional EE/DSM savings became more certain. (Tr. pp. 1586.140 – 1586.141.) Witness Snider additionally testified that evaluating high and low EE/DSM cases under different fuel and CO_2 assumptions would require an "extraordinary amount of additional work" that may be of limited value given that the Companies have already provided "individual high and low sensitivity on this variable" and included the High EE/DSM projections in three of the six portfolios. (Tr. pp. 1586.138 – 1586.139.)

In surrebuttal, Witness Grevatt responded to Witness Bak's assertion that utilities must consider "actual potential," again emphasizing that the MPS considered only historic participation rates and technologies, which provides no assurance that opportunities to cost-effectively obtain greater levels of energy efficiency are not being forsaken. (Tr. p. 673.13.) Mr. Grevatt explained at the hearing that "[t]his bottom up approach tends to lead to an underestimation" of potential and recommended improving on past savings levels by evaluating not just the known, "bottom-up" scenario but also "top-down" savings targets. (Tr. pp. 693:21 – 695:16, 708:2-3.)

In support of his recommendation to set higher saving targets, Witness Grevatt pointed to Colorado, where the PSCo utility has exceeded the saving levels its potential study indicated were possible following a commission order to do so. (Tr. pp. 673.14:17 – 673.16:2.) Likewise, in Maryland, the EmPOWER utilities have achieved annual savings equal to 2% of sales following a commission order dismissing the potential study as "only one of several tools." (Tr. pp. 673.16:3 – 673.17:7.) Consistent with these examples, the American Council for an Energy Efficient Economy has found that potential studies tend to underestimate achievable potential. (Tr. pp. 673.18:4 – 673.19:8.) Mr. Grevatt thus emphasized that though potential studies may assist with program planning, they are also "inherently conservative" and "should not be taken to represent the ceiling for achievable potentials." (Tr. p. 673.19:9-15.)

Also in response to Witness Bak, Witness Grevatt testified that it is only at the end of the product cycle when widespread adoption leads to lower net savings due to increased free ridership, which occurs only after a years-long period during which programs obtain significant savings. (Tr. pp. 673.4:17 – 673.5:3.) To illustrate this savings cycle, Mr. Grevatt provided two examples, including screw-based LED light bulbs which have generated significant savings for the Companies in the "middle of the product cycle," and heat pump water heaters, a newer technology which will become increasingly cost-effective under the UCT as it gains a greater market share and the fixed program costs are spread across more participants. (Tr. pp. 673.4:17 – 673.5:12.) Mr. Grevatt pointed out that Mr. Bak's statement is contradicted by the MPS itself, which recognizes that "[w]hen the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle." (Tr. p. 673.4:10-16.)

Witness Grevatt responded to Witness Herndon's testimony regarding the TRC, explaining that contrary to Mr. Herndon's suggestion that the TRC provides greater insight into customer expenses, the TRC looks only at total customer and utility costs without regard to whether the customer is paying 100% of the program cost or is reimbursed through a program incentive; thus, the TRC "provides no value in assessing customer likelihood to adopt measures." (Tr. pp. 673.9:19 – 673.10:11.) For this reason, members of the Collaborative recommended that Nexant evaluate achievable potential using the UCT as early as 2019, when the MPS was still in development. (Tr. pp. 673.8:19 – 673.9:8.)

In surrebuttal, Witness Hayet testified that, based on the Companies' response, his EE/DSM recommendations could be carried out in future IRPs. (Tr. pp. 2307.13 – 2307.16.) He did note, though, that even if it resulted in only minor changes, the Companies should consider in their IRP stakeholder process how to evaluate high and low EE/DSM cases across a range of fuel and CO_2 assumptions "to understand what level of EE/DSM should be implemented if fuel costs rise or if higher CO_2 costs are imposed." (Tr. pp. 2307.15:14 – 2307.16.7.)

Commission Conclusions

Having considered the evidence, the Commission concludes that the UCT is a more appropriate measure of cost-effectiveness than TRC for the purpose of developing the EE/DSM forecasts in the 2020 IRPs. As Witness Grevatt testified, the UCT evaluates the cost-effectiveness of EE/DSM from the utility system perspective, which is the appropriate consideration in an IRP proceeding. In addition, the UCT has been approved by the Commission as the primary cost-effectiveness test for Duke. Accordingly, the Commission finds it reasonable to require the Companies to use the UCT to estimate economic potential in developing EE/DSM scenarios and savings projections in its future IRPs and IRP updates.

To correct for the Companies' use of the TRC in the 2020 IRPs, the Companies shall in the modified IRPs apply a 10% increase to the achievable potential in the Base scenario when developing the Base DSM/EE projections in the IRPs, as the Companies have already done for the Enhanced scenario and corresponding High EE/DSM projections. Witness Bak supported the 10% increase as a reasonable estimate of the additional achievable potential that would be identified under the UCT. We are therefore persuaded that the same 10% increase should be applied to the Base Portfolio to simulate a more accurate measure of achievable potential in all EE/DSM portfolios. Because the Low EE/DSM projections are based on the Base EE/DSM projections, the 10% increase should apply to the Low EE/DSM projections as well.

The Commission is also persuaded by Witness Grevatt's testimony that the Company should model EE/DSM savings beyond the levels that have historically been achieved. The examples of Colorado and Maryland suggest that setting more ambitious savings targets than those identified in market potential studies is not speculative at all, but prudent given the inherently conservative nature of these studies. Accordingly, in future IRPs, IRP updates, and market potential studies, the Companies must work with the EE/DSM Collaborative to identify a set of reasonable assumptions surrounding 1) increased market acceptance of existing technologies and 2) emerging technologies to incorporate into EE/DSM saving forecasts. The Companies should also work with members of the Collaborative to ensure that residential saving projections are not overly dependent on behavioral programs with short savings persistence. Further, the Companies' next IRPs should identify which of the Collaborative's recommendations relating to market acceptance, emerging technologies, and types of programs were and were not adopted when developing market potential studies and IRPs.

Lastly, the Commission adopts Witness Hayet's initial recommendation that the Companies evaluate high and low EE/DSM cases across a range of fuel and CO_2 assumptions in future IRPs "to understand what level of EE/DSM should be implemented if fuel costs rise or if higher CO_2 costs are imposed." The Companies are encouraged to capitalize on EE/DSM saving opportunities to reduce energy costs, as well as the risk of rising energy costs, for all Duke customers.

C. Planning Reserve Margin and Winter Resource Adequacy

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 5

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony and exhibits in these dockets of Duke Witnesses Nick Wintermantel and Glen Snider, CCL et al. Witness James F. Wilson, ORS Witness Stephen Baron, and the entire record in this proceeding.

The Companies retained Astrapé Consulting to conduct resource adequacy studies, which attempted to model future loads based on predicted weather. These studies and the recommendations within formed the basis for the planning reserve margins used to develop the IRPs. Based on the results of the resource adequacy studies, the Companies used the SERVM model to calculate a planning reserve margin. (Tr. p. 1868:14-21.) Planning reserve margins attempt to ensure that the utility has sufficient capacity to serve loads during periods of high demand, specifically extreme cold. (Tr. p. 435:9-12.) The Companies attempted to set the planning reserve margin sufficient to satisfy a 1 day in 10 years resource adequacy criterion. (Tr. p. 612:8-15.) Under this criterion, a loss of load event occurs due to insufficient capacity resources only one day every ten years. (Tr. p.

375:8-12.) This is expressed as a loss of load expectation ("LOLE".) of 0.1. (Tr. p. 375:12-14.) The planning reserve margins play a key role in determining the extent and types of generating resources that were added under the IRPs. (Tr. p. 925:18-23.).

Duke Witness Nick Wintermantel, a principal at Astrapé Consulting, testified on behalf of the Companies concerning the resource adequacy studies. (Tr. pp. 368:2-6, 373:20 – 374:2.) Witness Wintermantel testified that winter peak load volatility is increasing for both DEC and DEP, which has led to increased winter resource adequacy risk in winter months. (Tr. p. 377:3 – 378:8.) Mr. Wintermantel acknowledged that much of the load during these winter peaks is attributable to electric residential heating. (Tr. pp. 435:25 – 436:25.)

Witness Wintermantel testified that one of the bases for the Companies' belief that the frequency of extreme cold weather events was increasing was a report from the Electric Power Research Institute ("EPRI".). (Tr. p. 437:2 – 438:12.) However, Mr. Wintermantel testified that he was unaware of the research underlying that report, which also found that cold extremes have become less severe over the past century. (Tr. pp. 439:5-20.) Mr. Wintermantel acknowledged that climate change has altered historical weather patterns. (Tr. p. 449:2-19.) While in the past Astrapé has adjusted temperature data to reflect these trends, the resource adequacy studies did not do so, instead weighting each year equally. (Tr. p. 449:13-21; Tr. p. 616.10:11-14.). Mr. Wintermantel testified that making this adjustment would have decreased the resulting reserve margin. (Tr. p. 449: 20-21.)

CCL et al. Witness James F. Wilson testified that the IRPs substantially overstated winter resource adequacy risk and this inflated risk drastically impacted the resulting planning reserve margins. (Tr. p. 612:4 – 613:13.) Witness Wilson found several major flaws in the resource adequacy studies. First, the Companies' resource adequacy studies used an inaccurate approach to estimate the impact of extreme cold on loads. (Tr. p. 612:16-21.) While the resource adequacy studies generally associated loads with temperatures using the "neural network" approach, this method was considered inaccurate at extreme high and low temperatures due to having fewer historical observations. (Tr. p. 616.8:17-20.) Instead, the resource adequacy studies used regression analysis to "extrapolate the peaks." (Tr. p. 616.8:20 – 616.9:1.) This approach assumed that for each additional degree the temperature drops, load increases by the same amount as at around 20 degrees. (Tr. p. 623: 19-25.) According to Mr. Wilson, this assumption is incorrect, and instead, as temperatures fall, the relationship between temperature and load becomes lower. (Tr. p. 624:3-6, 624:7-25.) Mr. Wilson also testified that the analysis also included observations up to daily minimum temperatures of 21 degrees and when those higher temperatures are excluded, the incremental impact of lower temperatures is much lower. (Tr. p. 616.9:20 – 616.10:2.) Mr. Wilson also testified that the method of combining the results of the analysis at extreme temperatures with the results of the "neural network" approach led to extreme and nonsensical load values. (Tr. p. 616.10:3-5.)

The second major flaw identified in the resource adequacy studies by Witness Wilson was that the resource adequacy studies inappropriately used 39 years of temperature data, from 1980 through 2018, and assigned equal weight to each year. (Tr. p. 612:22-25.) This data set included cold weather events that have not occurred in several decades. (Tr. pp. 612:22 – 613:5.) Inclusion of these events with equal weight overstates the future likelihood of those events occurring. (Tr. p. 616.10:17-19.) This weather data had an overwhelming impact on the results of the resource adequacy studies. (Tr. p. 613:6-

17.) Mr. Wilson explained that this impact was also alarming as typically in these types of probabilistic studies, the time period of weather data used should have little impact on the results. (Tr. p. 633:19 – 634:22.).

Witness Wilson also critiqued the RA Studies for overstating winter resource adequacy risk by including an unreasonable amount of forced power plant outages. Removing these forced outages would lower the reserve margins by approximately 1% per utility. (H.E. 18 pp. 26-27 [James Wilson Exhibit B p. 26-27].) According to Mr. Wilson, if all of the flaws in the resource adequacy studies were corrected, the planning reserve margin that was in place until the 2016 IRP—14.5% summer and 16.5% winter—would be more than adequate. (Tr. p. 616.6:5-8.)

Witness Wilson further noted several inconsistencies between the RA studies and the Companies' Winter Peak Study. (Tr. p. 613:18-22.) That study, which sought to research customer end uses that drive load during winter peak events and programs to reduce those loads, identified a study peak day with loads well below those included in the resource adequacy studies. In his rebuttal testimony, Duke Witness Snider explained that "the Winter Peak Study was not focused on an extreme weather event." (Tr. p. 1586.61:4-12.) However, because winter peak loads are inevitably driven by extreme weather events, the Companies' explanation of these inconsistencies is unclear. (Tr. p. 618.4:2-5.)

ORS Witness Stephen Baron testified that he found the Companies' reserve margins were reasonable, but noted that if two years were excluded from the RA Studies—1982 and 1985—the resulting reserve margins would drop significantly. (Tr. p. 930:11-21.). Like Witness Wilson, Witness Baron found that "low probability, low temperatures" drove the results of the modeling. (Tr. p. 937:22-24.). Mr. Baron questioned whether there should be a different time period used in order to capture changing weather patterns, but did not make a specific recommendation. (Tr. pp. 931 – 32, 937: 5-14.). Instead, Mr. Baron testified that any such decision "needs to be informed by climatological analysis." (Tr. p. 943:4-5.). Mr. Baron agreed with Mr. Wilson that the Companies need to "further develop their methodology to model the effects of extreme low temperatures on winter peak load." (Tr. p. 928.9:12-13.)

Commission Conclusions

In consideration of the above evidence, the Commission concludes that the Companies failed to sufficiently study the relationship between extreme winter weather and load; therefore, the Proposed IRPs do no meet the requirements of Act 62 to appropriately balance "[r]esource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins" with "[c]onsumer affordability." S.C. Code Ann. §58-37-40(C.)(2.). The evidence shows that the RA Studies substantially overstated winter resource adequacy risk and this inflated risk drastically impacted the resulting reserve margins. We agree with Witness Wilson's recommendation that the Companies study the relationship between winter weather and load and develop a more sophisticated method for estimating the potential impact of future winter weather on load for use in future IRP proceedings.

Consequently, the Commission finds it reasonable to require that the Companies study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load for use in future IRP proceedings. The Companies should prepare additional load forecast scenarios (such as high and low scenarios.), as required by South Carolina regulations, and also prepare forecasts of extreme or "90-10" summer and winter peak loads, that is, the peaks that are expected to occur only once in ten years. Lastly, the Companies should consider defining an alternative metric for expressing and communicating target reserve margins, which might use, in the numerator, an aggregate capacity value measure (reflecting load carrying capacity rather than installed capacity). An alternative metric might also use, in the denominator, a 90-10 extreme (rather than weather normal) forecast peak load value. Reserve margin targets defined in such terms, which could be presented together with traditional installed reserve margin measures, would be more robust and stable over time as load patterns and the capacity mix change.

D. Capacity Value of Solar and Storage

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 6 - 11

Summary of the Evidence

The evidence in support of these findings of fact is found in the testimony and exhibits in these dockets of CCEBA Witness Arne Olson and Duke Witnesses Matthew Kalemba and Nick Wintermantel.

Duke's IRPs use capacity expansion modeling computer software that dynamically evaluates combinations of resources to meet demand across all hours with a pre-defined level of reliability. As described by CCEBA Witness Olson, such modeling compares various resource paths to meeting load and the predefined reliability target in a least cost manner while achieving any policy goals such as risk reduction, generation diversity, coal retirement guidelines, energy efficiency requirements, et cetera. (Tr. p. 485.11:8-12.)

Testimony Regarding Modeled Synergistic Effects of Solar and Storage

CCEBA Witness Olson's testimony focused on the approach taken by Duke in its IRPs, comparing capacity expansion modeling to a football coach scrimmaging different combinations of players to determine the best lineup for the season. Witness Olson testified that a coach must consider each player's individual strengths in addition to the ways in which the players complement each other while capacity expansion software can model thousands of lineups using current and prospective players against various defenses to find which combination performs best over the course of minutes, hours, and years into the future. (Tr. p. 485.11:15-21.)

Witness Olson stated that, just as a coach must objectively understand the size, strength, stamina, and speed of individual players in assigning positions, capacity expansion modeling must have accurate inputs for individual resources–e.g., capacity, efficiency, fuel costs, ramp rates, outages, etc.–to predict how they will perform. (Tr. p. 485.12:1-4.)

The parties did not disagree on this basic point. Duke Witness Kalemba stated, "to properly evaluate resources in an IRP, it's important to know the capacity value of all the resources" to understand their contribution to meeting peak demand. (Tr. pp. 321-322.) And like individual players, individual resources interact with one another, and their combinations can provide capacity contributions greater, or smaller, than the sum of individual resources.

The parties also agreed in this case that solar and storage have recognized positive interactive benefits—referred to as "diversity" or "synergistic" benefits—for example, when daytime solar narrows the duration of a daily net peak period, which in turn allows storage to meet that net peak more effectively. (Tr. p. 485.12:8-12.) Nevertheless, while

Duke agreed that solar and storage have synergistic effects (Tr. p. 420:16-20), the capacity values of solar and storage, both individual and synergistic, were central contested issues in this case.

The key metric used to represent a resource's contribution towards meeting peak loads in capacity expansion modeling is ELCC: effective load carrying capability. Duke derived solar and storage ELCC values for use in its modeling from two separate studies. For battery storage, Duke commissioned Astrape Consulting to conduct a Storage ELCC Study completed in 2020, as stated by Duke Witness Wintermantel, a Principal Consultant and Partner at Astrape Consulting. (Tr. pp. 379.2:6-8, 379.13:1-6.) The study began by setting a system loss-of-load expectation of no more than once-in-ten years (0.1 LOLE) to represent a reliable generating system. Next, storage was added to the system to improve the loss-of-load-expectation to better than 0.1 LOLE. Finally, load was added back onto the system (modeled as a negative generator) until system reliability returned back to the 0.1 LOLE standard. This amount of added load, divided by the battery capacity, yielded the ELCC value of the storage resource. (Tr. pp. 379.13 – 379.14.) For solar, Astrape conducted a separate but similar study in 2018, assuming no significant battery storage on Duke's system. (Tr. pp. 424:1-11, 425:6-17.)

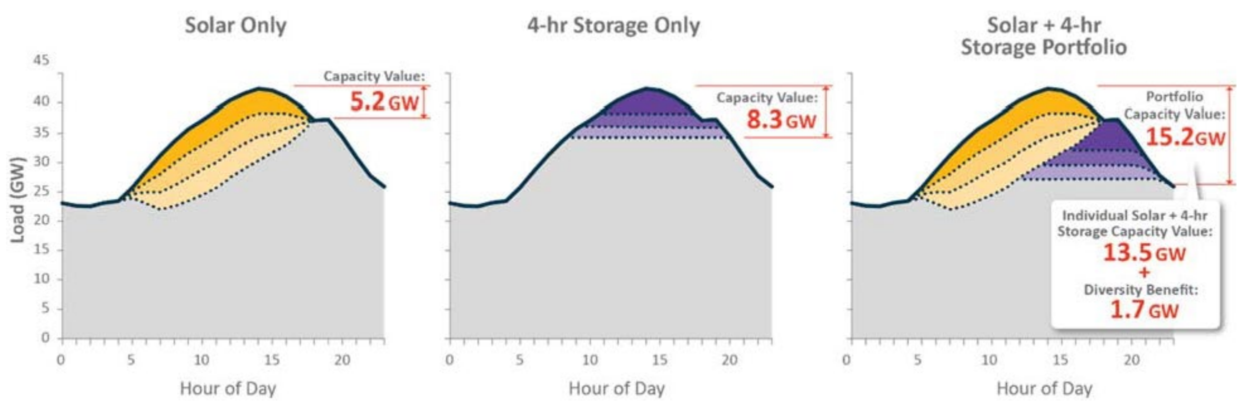
After determining the ELCC of solar and storage separately, Duke conducted optimization modeling using those values, with pre-selected amounts of solar placed on the system first and then, in a separate step, analyzing different storage volumes. (Tr. p. 427:3-11.)

As noted above, the parties all recognized that solar and storage have recognized positive interactive benefits–referred to as "diversity" or "synergistic" benefits. (Tr. p.

485.12:8-12.) Duke agreed that solar and storage have synergistic effects when deployed on the same utility system. (Tr. p. 420:16-20.) Duke Witness Wintermantel testified that adding storage can boost solar's effective capacity value by shifting its contribution towards peak periods of a day (Tr. p. 419:16-24), and that adding solar when storage is on the grid can increase storage's capacity by narrowing the net peak load that can be served by storage. (Tr. p. 419:11-15.)

Figure 1 below, while not specific to Duke, illustrates the point:

Figure 1: Illustration of the Synergistic Effects of Solar and Storage



(Tr. p. 485.12, Fig. 1.)

From left to right, the figure shows the impact on load from solar only, a 4-hour battery only, and solar and storage when combined. Considered separately, the solar and storage depicted in Figure 1 would have a combined capacity value of 13.5 GW. But if both solar and storage are added to a system, the combined capacity will be 15.2 GW, or 12% more. (Tr. p. 485.12:15-20.) This synergistic benefit of adding both solar and storage will only be apparent in the IRP process if the portfolio optimization including capacity expansion modeling is done to co-optimize all resource technologies, i.e. if all components of the capacity expansion are optimized at the same time, as opposed to sequentially. (Tr. p. 485.13:4-8.)

CCEBA Witness Olson testified that, while Duke recognized that solar and storage have synergistic values, it failed to capture those values because it determined the capacity values of solar and storage separately, and modeled them sequentially rather than simultaneously. According to Olson, this approach penalized solar because it did not capture solar's ability to boost storage's capacity value by narrowing the net peak window and provide energy for battery charging, nor did it capture the ability of storage, to increase solar's contribution to meeting load by discharging solar energy after dark and during winter periods. (Tr. p. 481:8-16.) Witness Olson stated that by effectively ignoring these diversity benefits, Duke artificially suppressed the respective capacity contribution of solar and storage in its modeling—not unlike a coach giving all credit for successful passing plays to the receiver but none to the quarterback or vice versa. (Tr. at 481:17-22.)

Continuing the metaphor, Witness Olson testified that to capture the two "players" combined offensive capacity, Duke should have first calculated and mapped their synergistic effects to produce an ELCC "surface" that could be fed into the portfolio optimization runs. (Tr. p. 481:22 – 482:1.) An ELCC surface is a modeling output that captures the interactive ELCCs of multiple resources at different penetration levels on a given system, including the benefits of combining resources with complimentary characteristics, like solar and storage. (Tr. p. 485.17:17-23.)

It is uncontested that Duke did not calculate or use an ELCC surface to capture the synergistic effects of solar and storage. (Tr. p. 389.32). It is also uncontested that Duke did not allow solar and storage to be modeled in "single step" mode. (Tr. p. 1586.132:3-4). In fact, Duke calculated solar's capacity value in 2018 without assuming any significant battery storage on Duke's system. (Tr. p. 424:1-11, 425:6-17.) And it never modeled whether additional storage on the system would increase solar's ELCC value including its value in winter loss-of-load events. (Tr. p. 426:9-12.) In fact, rather than include storage as a candidate resource, it instead substituted storage into the model as a replacement to CT capacity that the model had already selected. (Tr. p. 1847:2-6.) Thus, Duke substituted energy storage after optimization runs had already chosen a fixed amount of solar, such that storage was not allowed to co-optimize and increase the volume of solar; the smaller selected volume of solar, in turn, yielded a smaller, sub-optimal amount of storage, given that storage is most valuable at higher renewable penetrations. (Tr. p. 485.14:5-13.)

Duke Witness Wintermantel testified that this was a sufficient modeling method because Duke modeled various penetrations of storage. (Tr. p. 389.32). Witness Wintermantel also states that although solar is creating some of the opportunity for storage to supply capacity, the system should only "see" that credit when storage is selected in the portfolio since the benefit will not materialize until then. (*Id.*). Witness Wintermantel asserts that the capacity expansion planning performed by the Companies is appropriately allocating the diversity to the contingent resource decision. (*Id.*).

Witness Olson disagreed with Mr. Wintermantel, stating that Duke's approach failed to capture the synergies of solar and storage: solar was considered without the potential benefits of storage, while storage was considered only after the solar capacity was fixed. (Tr. p. 482:3-10.) He testified that this approach prevented Duke from identifying when the combination of solar and storage maximizes value for ratepayers. (Tr. p. 482:10-11.) In Witness Olson's opinion, Duke should have used a capacity expansion model capable of single-step optimization to deploy resource options simultaneously and capture the interactive effects of resources in various combinations. (Tr. p.482:11-19.)

Witness Olson testified that by omitting the full value of solar and storage's recognized synergistic effects, Duke's modeling tilted the playing field against solar and storage and disadvantaged their selection in candidate resource plans. Witness Olson referred to independent modeling by E3 showing that when solar and storage are modeled together, there is a diversity benefit of 25% in DEC and 20% in DEP. (Tr. p. 485.19:18-19.) For DEC, the individual ELCC values for solar are 679 MW and 721 MW for storage, totaling 1,400 MW of ELCC, but when modeled together, the total ELCC value for solar and storage is 1,811 MW. (Tr. p.485.19:20-22.) As shown in Witness Olson's testimony, these values are significantly higher than the Astrapé ELCC values, with the ultimate results converging at higher penetrations around 3,500 MW. (Tr. p. 485.27.)

In rebuttal, Duke Witness Wintermantel challenged the ELCC values for storage and solar calculated by E3 witness Olson on grounds that the values are annual rather than seasonal, and complained that E3's ELCC for stand-alone storage ELCC is too low. (Tr. p. 389.35.) Witness Wintermantel stated that the annual ELCCs presented by Witness Olson are not comparable to the capacity values used in the Companies' IRPs, which focus only on the winter ELCC values. (Tr. p. 389.35.) Witness Wintermantel also questioned the calculation of 4-hour stand-alone storage ELCC presented in Witness Olson's testimony and accompanying report as "exceptionally low". (Tr. p. 389.35.)

<u>Commission Conclusions</u>

The Commission concludes that Duke's evaluation of solar and storage prevented those resources from competing fairly in Duke's IRP capacity expansion modeling. Duke undervalued the capacity of solar and storage to reliably meet the needs of Duke's system—both separately and in combination—and by doing so obscured their ability to reduce system costs and ratepayer bills.

Duke's process unfairly skews the model against solar and storage and in favor of natural gas generation. The errors are not remedied by the fact that Duke's Storage ELCC Study analyzed storage penetrations "across two different solar tranches" (Tr. p. 389.32:11-12.) or its claims to have "enabled the synergies between solar and storage by allowing the model to select solar paired with storage resource." (Tr. p. 1390.43) Those exercises failed to measure or capture the *synergistic* capacity that storage brings to *solar's* ELCC, and the use of pre-determined tranches of solar volume meant that Duke's modeling did not determine the optimum quantities of solar *and* storage – or allow those combined optimized resources to compete against other sources of generation.

Nor did Duke calculate the synergistic effects of solar and storage and map those results onto a surface for use in single-step capacity expansion modeling that would allow these resources to compete on equal footing with resources like gas. To correct this error, the Commission directs Duke to use a capacity expansion model in developing its next IRP Update that is capable of the single-step optimization recommended by Witness Olson. In addition to using single-step optimization, Duke shall develop and utilize an ELCC surface as recommended by Witness Olson.

Testimony Regarding Individual Capacity Benefit of Solar and Storage

Storage ELCC – Preserve Reliability Mode

In addition to the above contention that Duke did not accurately model the synergistic value of solar and storage, CCEBA Witness Olson further testified that Duke also failed to accurately model and capture the capacity benefits of the resources individually. With storage, for example, Duke's modeling discounted the ability of batteries to help meet winter peaks by assuming battery storage would *not* be operated in a mode that maintains reliability and prevents loss of load. (Tr. p. 485.24).

Witness Wintermantel testified that Astrapé recognized that battery resources could be operated in three operating modes: (1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule. (Tr. p. 379.14:4-8) Under the Preserve Reliability Mode, the battery is fully controlled by the utility and is only used to provide energy during reliability events. While recognizing that this mode "would provide the most capacity value," Astrapé did not adopt that mode for planning modeling purposes, stating that running batteries in that mode during rare loss-of-load-events would be incompatible with other operational modes over the course of an operational year. (Tr. p.379.14:12-17.) When presented with evidence that batteries could indeed be run in the other modes most of the time but in Preserve Reliability Mode during rare reliability events, Duke initially contended that the capacity value difference between the preserve reliability mode and economic arbitrage mode is merely an average of 6% across all the stand-alone storage results. (Tr. p. 389.36.)

On cross-examination, Duke Witness Wintermantel admitted that with 1,200 megawatts of storage, there would be a 20% difference in the ELCC between Preserve Reliability and Economic Arbitrage modes (Tr. p. 403:19-22.) and that this value could impact the model's analysis of whether to add additional storage after 800 megawatts. (Tr. p. 405: 8-16.)

On surrebuttal, Witness Olson stated that even a 6% difference is similar to that seen for conventional resources for outage rates, which are highly consequential in determining loss of load and, therefore, should not be discounted. (Tr. p.1848:9-12.)

Commission Conclusions

The Commission concludes that by not modeling storage in Preserve Reliability Mode, Duke undercounted storage's capacity value and inaccurately prejudiced its ability to compete in modeling against other resources. This assumption should be revisited and storage should be modeled in Economic Arbitrage mode for comparison in modified IRPs to be filed within 60 days of the Commission's order.

Solar ELCC – Input for Solar Tracking Rate

Witness Olson testified that Duke underestimated solar's individual capacity value by assuming that new solar coming onto the Duke system would not feature single-axis tracking, which allows panels to follow the arc of the sun east to west and thereby maximize and extend production. (Tr. p. 485.25 -- 485.26).

Duke Witness Matthew Kalemba stated that the output and energy profile of a single-axis tracking solar panel, versus a fixed-tilt panel, comes from the panel ramping up earlier in the day and staying on later in the day thanks to the panel tilting towards the horizon. (Tr. pp. 1406-07.) Duke's own study showed single-axis tracking nearly tripling the resource's ELCC. (Tr. p. 1407:12.)

Nevertheless, Witness Kalemba testified that Duke's IRP relies on solar tracking assumptions in the 2018 Astrapé solar capacity study (Tr. p. 1408:18-22) and assumes that 40% of new installed solar would be fixed-tilt rather than tracking. (Tr. p. 429:15-21.) While Witness Kalemba agreed that future updates will need to take into account a higher percentage of single-axis tracking, and that Duke "should be adjusting the percentage for those," (Tr. p. 1404:13-14.), he and Duke maintain that adjusting to 100% fixed-tilt is not warranted and the 40% fixed-tilt assumption is reasonable for now. (Tr. pp. 1404:14-23; 1406:1.)

Commission Conclusions

The Commission concludes that Duke's modeling fails to adequately take into account the presence and growing predominance of single-axis tracking solar facilities in the DEC and DEP footprint. The assumption that 40% of new installed solar will be fixed-tilt rather than tracking is at odds with present reality: the facilities chosen in Duke's own CPRE Tranche 2 solicitation are 100% single-axis tracking. (Tr. p.1406:1.) Duke underestimated solar's capacity value by assuming that 40% of new solar would have single-axis tracking, when in reality none of it likely will. The assumption is not reasonable and should be corrected in modified IRPs to be filed within 60 days of the Commission's order.

Solar and Storage ELCCs: Outage Rates and PRM Accounting

While Duke used the ELCC method for calculating the capacity value of solar and storage, Witness Olson took issue with Duke's use of a separate measure—the installed capacity ("ICAP") method—in calculating the system planning reserve margin ("PRM"). Olson testified that this decision tilted the playing field in favor of thermal (gas and coal) resources. (Tr. p.480: 17-22.)

Witness Olson testified that the PRM is a standard approach to ensuring system reliability by establishing the quantity of generating capacity needed to ensure a given reliability level, usually targeted to be one outage every ten years (the 0.1 LOLE standard).

(Tr. p. 485.28:19-22.) Once the PRM is established, the utility can model different combinations of resources to meet the desired reserve margin. (Tr. p. 485.29:1-2.)

Witness Olson's criticism of Duke's approach notes that in the past, PRM accounting and use of the ICAP method was relatively simple because most generating capacity was available at full capacity except in the event of forced outages. (Tr. p. 485.29.) More recently, Witness Olson testified, the industry has turned to ELCC as the preferred method for measuring the resource adequacy contribution of intermittent or dispatch-limited resources. (Tr. p. 485.29:7-10.) Duke has adopted the ELCC approach for renewables, but Duke continues to use its existing ICAP PRM method for thermal resources. Witness Olson maintains that ICAP is incompatible with ELCC and undervalues intermittent resources in comparison to firm resources. (Tr. p. 485.29:10-13.) Specifically, the ICAP method assumes perfect production from thermal resources without forced outages, while the ELCC calculation takes a resource's unavailability into account. Said another way, the ICAP PRM model assumes that all firm resources are available at their full nameplate capacity, such that a coal unit with 500 MW nameplate capacity and a 5% forced outage rate would be given a capacity value contribution of 500 MW. (Tr. p.485.28:17-19.) By contrast, ELCC derates the nameplate capacity of a resource to account for times when it is unable to generate electricity and represents the amount of that resource that can support peak load – similar to another metric for calculating planning reserve margin, the unforced capacity ("UCAP") method. (Tr. p. 485.30:5-9.)

Witness Olson returned to a coaching metaphor and testified that the use of an ICAP PRM with ELCC for intermittent resources is like a coach using a different stopwatch for certain players (in this case, thermal resources) that shaves half a second off of their 40-

yard dash times versus other players (solar). (Tr. p. 481:1-3.) To level the playing field, Witness Olson recommended that Duke should use the industry best practice UCAP method, which is a relatively simple change that could be made very quickly. (Tr. p. 481:5-7.)

Duke Witness Snider disagreed with Witness Olson's critique of the ICAP method, stating that use of the UCAP planning reserve margin would require a significant re-design of the current planning reserve margin process. Witness Snider also asserted that new thermal resources have very low forced outage rates such that the use of the UCAP method would have very little impact on the expansion plan and selection of resources. (Tr. p. 1586.66.)

On cross-examination, Duke Witness Wintermantel admitted that he had previously submitted testimony to the New Mexico Public Regulation Commission in April 2021 noting that "the change from ICAP to UCAP for comparison to ELCC resulted in intermittent and other resources being fairly compared to traditional resources for capacity purposes." (Tr. p. 413: 4-10.) Witness Wintermantel maintains that such a step is unnecessary in this IRP modeling because Astrapé relied on a 2018 solar capacity value study which had not modeled E4 outage rates for the solar resources in the portfolios, reducing the difference between ELCC and ICAP, which Witness Wintermantel stated "somewhat neutralizes Witness Olson's argument." (Tr. pp. 413:17-21.) On cross-examination, Wintermantel was unable to specify what the E4 outage rate of solar should be. (Tr. p. 415:11-12.)

<u>Commission Conclusions</u>

Duke's use of the ICAP PRM method for thermal resources combined with the ELCC method for determining the capacity value of solar and storage judged those renewable resources by a different, disadvantageous standard. Duke should use the UCAP rather than the ICAP method for thermal resources and continue to use the ELCC method for solar and storage. This will provide a more accurate comparison of the capacity contribution of all available resources.

<u>ELCC as a Function of Load</u>

It is uncontested that the ELCC of a resource is a function of the loads and resources that are on a system. If more of a resource is added and load is held constant, that resource provides a larger percentage of total capacity requirements and its ELCC will decline. Conversely, as loads grow, a given resource effectively provides a lower percentage of total capacity requirements, meaning its ELCC will increase. Thus, the ELCC of 100 MW of solar on a system of a 15,000 MW peak load will be significantly larger than 100 MW of solar on a smaller but otherwise equivalent system of 1,500 MW peak load. (Tr. p. 485.21).

Duke calculated solar ELCCs relative to 2020 load levels and storage ELCCs relative to 2024 levels. (Tr. p. 485.21.) Witness Olson testified that this approach effectively underestimates the ELCC of solar and storage in years beyond 2020 and 2024, respectively, when load levels will be higher due to growth. (Tr. p.485.21:12-19.) Duke does not deny that its load will grow; indeed, it predicts it.

Witness Olson recommends that Duke use year 2040 loads for this modeling or, in the alternative, year 2035 loads. (Tr. p. 1849:5-6.) Duke objects to the use of 2040 loads as being outside the 15-year planning horizon of the IRP. (Tr. p. 387:5-9.)

Commission Conclusions

The Commission concludes that year 2020 and 2024 loads are inappropriate for an IRP that evaluates resources over a 15-year timeline. Duke's error undervalued the capacity value of solar and unfairly prejudiced its ability to compete against other resource options.

E. Coal Retirement Analysis

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 12

a. Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRPs, pleadings, testimony of Duke Witness Glen Snider, ORS Witness Philip Hayet, CCEBA and CCL et al. Witness Rachel Wilson, as well as exhibits in these dockets, and the entire record in this proceeding. pleadings, testimony and exhibits in this docket, and the entire record in these proceedings.

Duke's coal fleet has operated for decades, with plants ranging from 37 to 63 years old. (H.E. 1, Table 11-A) Although they were designed and built as baseload units, (Tr. p. 1143:21-25), many of Duke's coal units are now operating as peaking or cycling plants, with capacity factors in the single digits. (H.E. 56 [Exhibit RSW-2 p. 6, Table 2].) At the direction of the North Carolina Utilities Commission, in preparing the 2020 DEC and DEP IRPs, Duke conducted two different coal retirement analyses: "earliest practicable" and "most economic." (Tr. p. 1726:20-1727:1; Tr. p. 1586.91:15-17.) According to Duke Witness Glen Snider, the "earliest practicable" coal retirement analysis "set[] aside normal least cost planning principles to determine the earliest date at which the coal units could be retired[.]" (Tr. p. 1586.92:3-5.) The "most economic" analysis, in contrast, used least cost planning principles. (Tr. p. 1586.91:19-20.) Both analyses took into account transmission, distribution and replacement generation. (Tr. p. 1586.92:1-3.) The retirement dates determined through the "most economic" analysis were assumed in both the "Base Case With Carbon Policy" and "Base Case Without Carbon Policy" in each IRP. (H.E. 1 p. 79.)

Most of the testimony on coal retirements at the evidentiary hearing focused on Duke's "most economic" coal retirement analysis, which Duke conducted as follows. Prior to beginning the analysis, Duke estimated the future capital and fixed operating and maintenance costs of each coal unit over various useful lives. (Tr. p. 1728:10-11.) Duke then proceeded with the first step of its analysis: ranking the DEC and DEP coal units. Witness Snider testified that the ranking was done based on multiple metrics: the units' capacity, the reserve margin and capacity length, capacity factor and remaining life. (Tr. p. 1727:10-17.) The average capacity factors used in Duke's retirement analysis ranged from 2.6% (Mayo Unit 1) to 30.5% (Belews Creek Unit 1), with most between 2.6% and 8.4%. (H.E. 56 [Exhibit RSW-2 p. 6, table 2].) The IRPs state that Duke considered each plant's capacity to be one of the most important metrics in the analysis, assigning it higher importance than other metrics like capacity factor. (H.E. 1 [DEP 2020 IRP p. 83].) Mr. Snider testified that a plant's retirement date could potentially change if Duke used a different ranking, but held everything else constant. (Tr. p. 1738:15-19.)

The second step in Duke's "most economic" retirement analysis used an internally developed process, which Duke termed the Sequential Peaker Method ("SPM"), to determine the retirement dates for its coal plants. (Tr. p. 2151.8:15-16.) The SPM is based on the Net Cost of New Entry ("Net CONE") method, which compares the capital and fixed costs, as well as the net production value, of a new natural gas combustion turbine (or "peaker") plant to those of each existing coal unit. (Tr. p. 2151.8:17 – 2151.9:3; H.E. 1 [DEP 2020 IRP p. 83].) To do this, the SPM relied partly on an optimization analysis using the Companies' System Optimizer capacity expansion model, and partly on a series of production cost modeling runs using the Companies' PROSYM production cost model. (Tr. p. 856.17:13-17.) Witness Snider testified that the SPM "picks the appropriate retirement date when an actual peaker was determined to be economic compared to the retiring coal unit." (Tr. p. 1586.95:23 – 1586.96:2.) According to Mr. Snider, in this step, Duke assumed the coal capacity would be replaced on a one-for one basis. (Tr. p. 1738:7-10.) The retirement dates derived via the SPM analysis are shown in Table 11-B of the DEC and DEP IRPs. (H.E. 1.)

In the third step, having determined the retirement dates using the SPM, Duke used capacity expansion and production cost modeling to develop two portfolios that assumed those coal retirement dates and selected replacement resources. (H.E. 1 [DEP 2020 IRP p. 87].)

ORS and intervenor witnesses critiqued various aspects of the methodology and assumptions employed in Duke's "most economic" coal retirement analysis. According to CCEBA and CCL et al. Witness Rachel Wilson, the SPM does not comport with industry practice. (Tr. p. 2151.9:11-12.) Comparing an existing coal unit to a combustion turbine could overstate the cost of replacement capacity; a combination of solar, wind, batteries, and DSM measures would likely be a more cost effective replacement portfolio than a combustion turbine. (Tr. p. 2151.10:4-9.) Duke did not evaluate such a portfolio until the third step of its analysis, however, when the "economic" retirement dates had already been selected. (Tr. p. 2151.10:10-11.) Ms. Wilson recommended that the Commission require Duke to complete a new coal retirement analysis that adheres to industry best practices and optimizes for both retirement dates and replacement resources. (Tr. p. 2151.8:3-5.)

With regard to Duke's modeling approach in the SPM, ORS Witness Hayet expressed a concern that a better approach might be to rely entirely on an optimization method, and recommended that the Companies provide evidence that the optimal retirement dates that were determined with the SMP are comparable to the optimal retirement dates the System Optimizer model would produce. (Tr. p. 856.17:21 – 856.18:2.) Witness Snider responded that in conducting the retirement study for the 2020 IRPs, it was not practical to conduct such an analysis due to limitations in the capacity expansion model, the complexity of the analysis, and the magnitude of the coal retirements being contemplated. (Tr. p. 1586.86:7-14.) However, Mr. Snider testified that "[t]o the extent the new Encompass software is capable of fully optimizing retirement dates and replacement options, the Company will agree to perform that analysis in the comprehensive IRP filing in 2022." (Tr. p. 1586.85:15-18.) Mr..Hayet testified that this proposed resolution to ORS' recommendation was reasonable. (Tr. p. 2307.21:3-7.) Witness R. Wilson likewise acknowledged Mr. Snider's testimony on that point, and stated that including an updated analysis in the 2022 IRPs would be sufficient. (Tr. p. 2151.13:12-13.)

b. Commission Conclusions

In light of Act 62's requirement that a utility consider facility retirement assumptions, S.C. Code Ann. § 58-37-40(B)(1)(e)(ii), (f), the Commission concludes that the results of Duke's "most economic" retirement analysis are an important underpinning to the Companies' IRPs and should therefore be as accurate as possible. In light of the evidence, however, the Commission finds that Duke's "most economic" retirement analysis contained flaws that call into question the reasonableness of its results.

With regard to the ranking of the coal units, although Duke used multiple metrics, it is clear that Duke assigned outsized importance to each plant's capacity rating, and indeed, the resulting ranking is from smallest capacity to largest, with the exception of Allen Units 1-3. (H.E. 1 [DEP 2020 IRP p. 82].) The results of the ranking are significant, given Witness Snider's testimony that the retirement date could potentially change if Duke used a different ranking while holding everything else constant.

With regard to the SPM, the Commission is persuaded by the critiques of Witnesses Hayet and R. Wilson. The SPM likely overstated the cost of replacement capacity by assuming replacement of each megawatt of coal capacity on a "one for one" basis rather than based on projected system capacity and energy needs, and by comparing the coal units with the cost of a gas combustion turbine, rather than a portfolio of resources such as wind, solar, storage, and energy efficiency. The Commission agrees with Mr. Hayet's recommendation that Duke should use an optimization model to derive optimal resource plans, with and without the target retirement unit, to determine the optimal retirement date for the target retirement unit.

The results of Duke's analysis themselves also call the rigor of the analysis into question: Even though depreciation book life was not a variable in the SPM analysis, (Tr. p. 1739:20-21), with the exception of Allen units 2-4, none of the economic retirement dates identified in Duke's retirement analysis occur any earlier than the end of the units' depreciable lives. (Tr. pp. 2151.9:1-3, 2151.10, table 1.)

In light of the evidence, the Commission cannot conclude that Duke's retirement analysis produced the most economic retirement dates for the DEC and DEP coal units, or an optimal portfolio of replacement resources. Accordingly, the Commission will require the Companies to complete a new comprehensive coal retirement analysis that adheres to industry best practices, corrects the flaws identified by Witnesses Hayet and R. Wilson, and optimizes for both retirement dates and replacement resources, and to incorporate that analysis in the 2022 IRPs.

F. Modeling Assumptions and Inputs

1. Duke's Natural Gas Forecast Methodology

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 13-15

The evidence in support of these findings of fact is found in the testimony and exhibits in these dockets of CCEBA Witness Kevin Lucas, Duke Witnesses Glen Snider and Dewey Roberts, and ORS Witness Philip Hayet.

Duke's IRPs model several scenarios, all but one of which anticipate an increase in the amount of natural gas generation over the planning period. In all of the scenarios, Duke plans to close its coal facilities over the coming decades, and the energy and capacity of those plants must be replaced by some combination of resources, which differ according to the scenario.

CCEBA Witness Kevin Lucas provided commentary regarding the natural gas pricing and modeling employed by Duke in its IRPs. (Tr. pp. 501.7, 501.22 – 501.28, 501.65 – 501.104.)

a. Gas Supply Assumptions

Summary of the Evidence

On the issue of supply, Mr. Lucas stated that Duke assumes that there will be a firm capacity to deliver natural gas at a constant price to its anticipated new combined cycle ("CC") units, where the recent cancellation of the Atlantic Coast Pipeline and the write-down of the Mountain Valley Pipeline make such an assumption unreasonable. (Tr. pp. 501.8:19-21; 501.28:8-10.) As for the combustion turbine ("CT") units, Lucas stated that Duke does *not* assume a firm fuel delivery for those units, despite their increasing usage during winter mornings and evenings when heating load is at its highest. (Tr. p. 501.28:10-11.) Duke Witness Roberts, under cross-examination, later agreed that Duke does not assume a firm delivery for CTs, but that Duke keeps backup fuel at each CT site, and while he had never known the gas supply to be interrupted, it could be limited. (Tr. p. 1087:17-1088:6.)

Commission Conclusions

The Commission concludes that Duke's assumption of a ready firm supply capacity for natural gas to its facilities without regard to pipeline risk is unreasonable. Duke shall be required to specifically address and account for supply capacity risk in future IRPs.

2. Natural Gas Price Forecasts

Summary of the Evidence

CCEBA Testimony

CCEBA Witness Lucas stated that "[t]he company's natural gas forecast methodology is flawed, relying too long on forward contract prices and failing to [include] risk in its price forecast." (Tr. p. 494:10-13.) Lucas testified that "Duke's model currently favors natural gas over renewables and storage to replace the retiring coal . . . However, this modeling outcome is not a reflection of the merits of natural gas over renewables, but is instead a mathematical result of the model's assumptions." (Tr. p. 501.66:5-8.)

Witness Lucas disagreed with several gas-related modeling assumptions Duke used in its IRPs: (1) Duke used a natural gas price forecast based on low market prices[5] from the illiquid portion of the natural gas futures price curve; (2) Duke then used that low market price exclusively for ten years, and partially relied on it for the next five years of the model, biasing the model towards building and running natural gas assets throughout the planning horizon; and (3) the resulting portfolios (with the exception of the "No New Gas" portfolio) showed "the addition of massive quantities of natural gas generation well into the future." (Tr. pp. 501.66:8–501.67:2.)

Witness Lucas noted that Duke supported its 10-year gas forecast prices on its ability to purchase a 116-month fixed price swap for 2,500 dts/day for May 2020 through December 2029. (Tr. 501.70:1-5.) Witness Lucas testified that these futures contracts[6] – priced beyond two years – are inherently volatile and illiquid due to limited trading, and are, in Lucas's opinion, irrelevant to determine the price at which Duke would be able to purchase tremendously larger quantities of natural gas in the future. According to Witness

[5] Although the parties used the term "market prices" with respect to Duke's forecast methodology, there was considerable disagreement as to whether there is a robust, liquid "market" (in the traditional sense) for natural gas contracts up to ten years in the future. Unless otherwise stated, the Commission uses the term "market prices" here for convenience, without concluding that a true "market" for the delivery of natural gas ten years in the future exists.

[6] Mr. Lucas clarified that Duke did not actually obtain "futures contracts" for the entire 10-year period, but for some period of time purchased fixed-price swaps. (Tr. p. 501.70-71.) Swaps and futures contracts are related but distinct products. Futures contracts are standardized and settled through a public exchange, while swaps are bilateral contracts that do not have standard terms. (Tr. p. 501.71:8-12.)

Lucas, "[Duke] procured 2,500 decatherms/day, equal to 2,500 MMBtu per day. In a natural gas combined cycle unit with a typical heat rate of 7,000, this is sufficient to generate about 357 MWh per day or 130 GWh per year. Considering that DEC and DEP combined have forecasted sales of 154,228 GWh in 2020, the natural gas fuel needed to supply 0.08% of Duke's annual generation secured by the swap is simply *de minimis.*" (Tr. pp. 501.76:3 – 501.77:9.) Further, Lucas stated that Duke locked in its market price forecast on April 9, 2020, in the midst of a period of major futures market volatility, and very near to the lowest price point in the market in several years. (Tr. p. 501.87:9-11.) Had pricing been locked in on a different day, the natural gas prices for the first 15 years of the IRP would have been substantially different, resulting in different IRP results. (Tr. p. 501.87:11-15.) This, Lucas stated, is evidence that these futures-based prices are too unstable to be relied upon for long-term projections.

Witness Lucas also took issue with Duke's natural gas price forecasts. According to Lucas, because Duke's riders pass fuel costs through to retail customers, any risk in natural gas forecast error is borne by ratepayers, and not by Duke's shareholders. (Tr. p. 501.28:6-7.) Lucas testified that Duke's natural gas pricing assumptions can dramatically impact the capacity additions selected during the IRP modeling process, and it is therefore essential for ratepayers that gas price projections are subjected to very close scrutiny. (Tr. p. 501.102:4-12.)

As detailed in reports by witnesses for ORS, and quoted with approval by Duke Witness Snider, Duke adopts a pricing methodology "of using market-based pricing for the first 10 years (2021-2030) and then gradually transitioning to a 100% fundamentals-based forecasting approach." (Tr. p. 1586.67:11-13.) Snider stated that ORS and Kennedy

Associates "correctly explain that the Companies' 'market-based forecast came from a NYMEX natural gas price strip actually purchased by the Company on April 9, 2020, which the Company used as its market assumptions for 2020-2030. Beginning in 2031, the natural gas price strip was blended with a long-term fundamental natural gas price forecast that the Company obtained from its vendor, IHS Markit ("IHS"), which was referred to as the North American Natural Gas Long-Term Outlook, February 2020. By 2035, the forecast was completely based on the IHS fundamentals forecast." (Tr. pp. 1586.67:13 – 1586.68:2; *see also* H.E. 16 [KL-19].)

Witness Lucas testified that Duke's forward market forecast, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid-2030s, when Duke's capacity needs arise. Figure 33 from Lucas's direct testimony sets out the difference between the annual low natural gas forecast set out in the IRP (IRP Figure A-2) and the low-price scenario from the Energy Information Administration's Annual Energy Outlook ("AEO"). (Tr. pp. 501.99 – 501.100.)

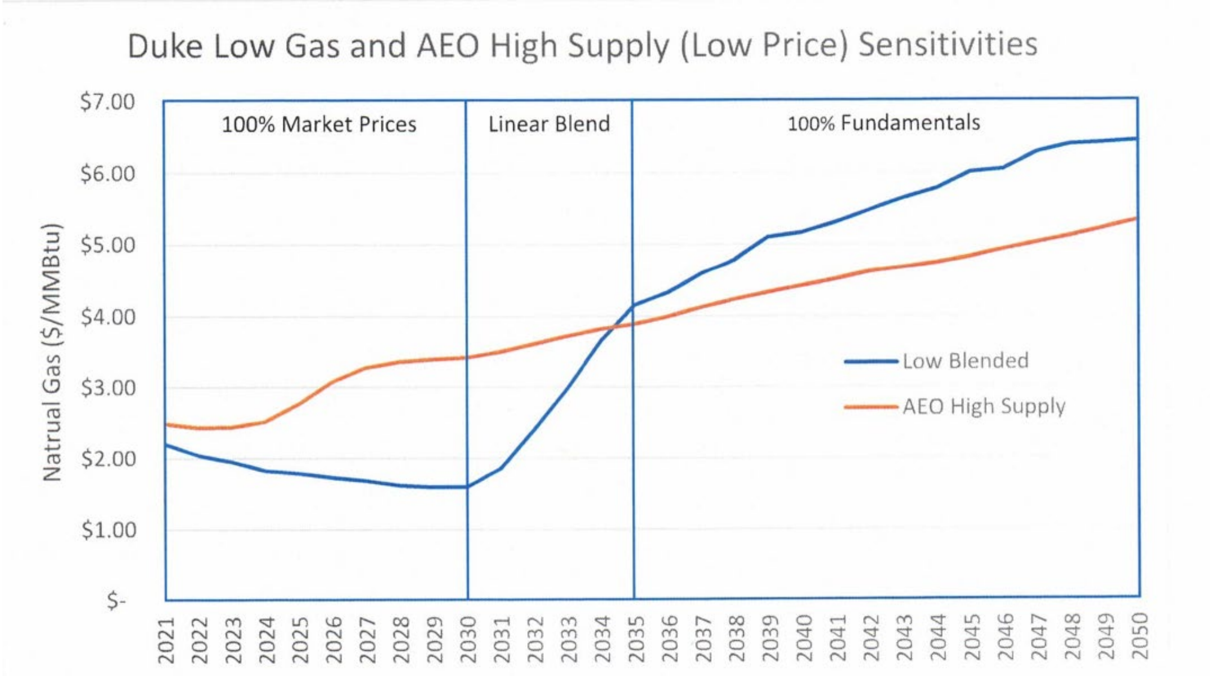


Figure 33 - Duke Low Gas and AEO High Supply (Low Price) Sensitivities

Witness Lucas further testified that Duke's forecast is arbitrary, stating that "Duke expects the natural gas industry to reduce prices after inflation by 3.5% per year in the 2020s, then increase at an annual rate of more than 18% between 2030 and 2035, before slowing growth to an annual rate of 2.9% from 2036 and beyond. It is difficult to fathom a combination of policy scenarios that would produce this curve exactly because no combination of policy scenarios would produce this curve." (Tr. p. 501.99:6-12.) Witness Lucas stated that the AEO curve, on the other hand, is internally consistent and fundamentals-based. (Tr. pp. 501.99:15 – 501.100:2.)

Witness Lucas next objected to Duke's choice to use the 10th and 90th percentile in its price sensitivities, stating that Duke is using values from one-in-ten likelihood forecasts, which are more extreme and unlikely, and which exacerbate the risk of the market price moving too far from the central value. (Tr. p. 501.100:7-10.) Lucas recommended that, in basing the natural gas pricing scenario on market prices for the first 36 months of the forecast period, Duke use the 25th and 75th percentile results, to reduce the random volatility of the market. (Tr. p. 501.100:11-16.)

Witness Lucas suggested in his testimony that Duke be required to remodel their portfolios based upon more realistic natural gas pricing, using market prices for 18 months, followed by transitioning over 18 months to the average of at least two fundamentals-based forecasts. (Tr. p. 501.101:13-20.)

Witness Lucas noted in Figure 36 to his pre-filed direct testimony that Duke's method resulted in lower natural gas prices through the 2020s and into the 2030s than fundamentals-based forecasts would predict. (Tr. p. 501.104.)

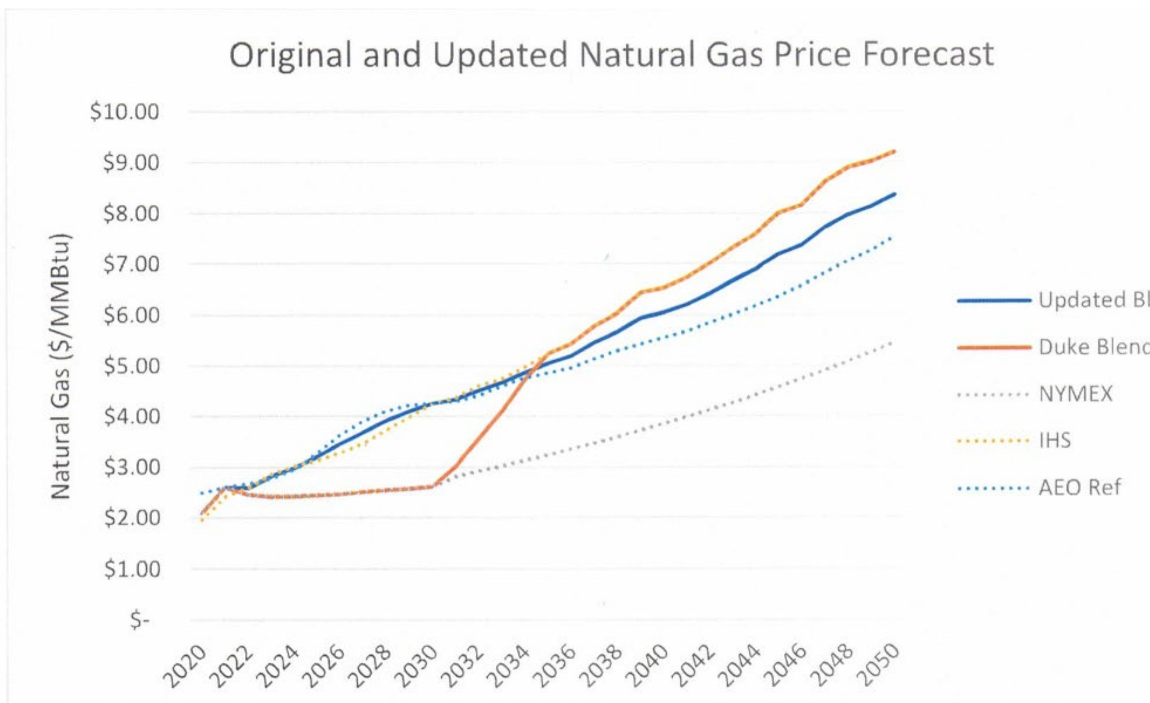


Figure 36 - Original and Updated Natural Gas Price Forecast

ORS Witness Philip Hayet echoed this concern, noting that ORS "compared the Companies' Low, Base, and High Henry Hub natural gas price forecasts to other recent Henry Hub forecasts for other utilities that were obtained from publicly available sources and found that the Companies' three forecasts were consistently lower than the other utility forecasts over the period of 2021 to about 2034. After 2034, it appears the Companies' three forecasts ultimately trend towards the average of all of the forecasts that were reviewed." (Tr. pp. 856.13:18 – 856.14:1.) Hayet stated that while ORS did not consider Duke's price forecasts to be "outliers" when compared to other utilities, ORS did have a concern "that low gas price forecasts could bias results in favor of selecting too many natural gas-fired resources." (Tr. p. 856.14:3-5.) Hayet testified that it would be "worthwhile" for Duke to "conduct further investigation of the natural gas forecasting methodology" and address any changes in future IRPs through a stakeholder process. (Tr. p. 856.14:5-8.)

Duke Rebuttal Testimony

In response to Witness Lucas's critiques, Duke Witness Snider noted that ORS and Kennedy Associates "extensively reviewed the methodological approach to natural gas forecasting and the Companies' resulting low, base, and high natural gas price forecast assumptions" and found that it "d[id] not appear to be unreasonable." (Tr. pp. 1586.66:22 – 1586.67:6.) Witness Snider noted that ORS indicated "some concern that relying upon an unreasonably low natural gas forecast 'could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resources alternatives.'" (Tr. p. 1586.68:11-14 (citing H.E. 56 [ORS Report (DEC) p. 50; ORS Report (DEP), p. 50]).) Snider then stated that he understood that ORS ultimately "recommend[ed] the Companies review its [sic] natural gas price forecasting methodology and investigate alternative approaches to be addressed in future IRPs through the Company's stakeholder process." (Tr. p. 1586.68:15-18.)

Witness Snider noted that the North Carolina Utilities Commission ("NCUC") had previously approved reliance on forward prices for natural gas in several proceedings, including, most recently, a 2018 avoided cost proceeding. (Tr. pp. 1586.70:10 – 1586.71:14.) Snider attributed Witness Lucas's testimony to financial interest, stating that if Witness Lucas's position in favor of fundamentals-based forecasting were to be adopted, "the solar development community would be poised for significant monetary gain as his arguments would be carried forward to the upcoming avoided cost proceedings in North Carolina or South Carolina." (Tr. p. 1586.72:7-12.)

Witness Snider denied that natural gas market prices could be characterized as "highly volatile," instead stating that fundamental forecasts "can vary significantly over time and can vary from one forecast provider to the next." He further stated that fundamental forecasts have "consistently overstated the market over the last several years." (Tr. p. 1586.74:6-22.) Snider testified that Witness Lucas was "simply incorrect" in stating that the natural gas market lacks liquidity over a ten year period, stating that "the robustness of a market can be demonstrated by the fact that there are multiple brokers that will transact natural gas swaps over this period." (Tr. p. 1586.77:1-15.)

Witness Snider also testified as to the mechanics of natural gas hedging, taking issue with Witness Lucas's statements about the small volume of Duke's swaps on which their market price forecast is based. (Tr. p. 1586.78:2-17.) In response to Lucas's recommendation to move to fundamentals-based forecasting, Snider testified that "use of fundamental market prices that are in excess of actual market prices is flawed and would result in significant customer overpayments if the same logic was followed in the upcoming avoided cost docket." (Tr. p. 1586.82:8-10.)

CCEBA Surrebuttal

In response to Snider's argument that the ORS had approved the natural gas pricing methodology, Witness Lucas noted that ORS made several findings that called that methodology into question, including ORS Witness Hayet's concerns that it could result in lower than proper prices. (Tr. pp. 1911.25:4 – 1911.26:15.) While ORS recommended those concerns be addressed in future IRPs and IRP updates, WitnessLucas testified that waiting until future IRPs to address these concerns would not be the most reasonable and prudent approach. Witness Lucas emphasized that most of the scenarios in Duke's proposed IRPs commit to substantial increases in natural gas generation before 2035, and even greater increases from 2035 – 2040, as shown in Table 1 to Witness Lucas's Direct Testimony. (Tr. p. 501.22.)

	By 2035			By 2041		
	CC	CT	Total	CC	CT	Total
2020 Capacity	4,940	5,520	**10,460**	4,940	5,520	**10,460**
Incremental Capacity						
Base without Carbon Policy	3,672	5,941	**9,613**	4,896	12,796	**17,692**
Base with Carbon Policy	3,672	3,656	**7,328**	4,896	10,054	**14,950**
Earliest Prac. Coal Retirement	3,672	5,941	**9,613**	3,672	10,968	**14,640**
70% CO2: High Wind	3,672	2,742	**6,414**	3,672	5,484	**9,156**
70% CO2: High SMR	2,448	3,656	**6,104**	2,448	6,398	**8,846**
No New Gas Generation	0	0	**0**	0	0	**0**

Witness Lucas stated that "[b]y 2035, the first three scenarios add three new 1,224 MW CCs while increasing CT capacity by roughly two-thirds (Base with Carbon Policy) or more than double (Base without Carbon Policy and Earliest Practicable Coal Retirement). The 70% CO2: High Wind adds fewer CTs through 2035, offset by increasing battery deployment. Unsurprisingly, the No New Gas Generation portfolio adds no new gas generation." (Tr. p. 501.23:2-6.) Witness Lucas described the additional build through

2040 as " truly staggering," noting that "[t]he two Base cases each add another 1,224 MW CC facility. The Base without Carbon Policy more than doubles incremental CTs, bringing nearly 7 GW of additional capacity online by 2041. The Base with Carbon Policy portfolio adds nearly as much, with 6.4 GW of new CTs. These additions represent the largest proposed natural gas expansion of any utility in the country by far." (Tr. p. 501.23:7-12.)

Witness Lucas also responded to Witness Snider's claim that the NCUC had approved a market-based forecast by noting that, to the contrary, "the NCUC has repeatedly rejected Duke's natural gas forecasting methodology and its over-reliance on near-term market data." Lucas went on to discuss several NCUC decisions limiting the duration of market-based modeling and limiting the precedential value of decisions finding such pricing to be acceptable for other purposes. (Tr. pp. 1911.27:7 – 1911.28:2.) Lucas noted as well that Duke repeatedly failed to abide by the NCUC's orders. (Tr. pp. 1911.28:18 – 1911.29:3.)

Finally, Witness Lucas emphasized the importance of natural gas pricing decisions in the context of these IRPs. Witness Lucas testified that approvingDuke's IRP modeling or delaying reconsideration of its approach until future IRPs would risk cementing in an unwarranted preference for natural gas generation. Witness Lucas argued that fundamentals-based pricing projections, which do not lock in a low price for an unreasonable time, show that natural gas is not competitive with solar's more predictable pricing. (Tr. pp. 1911.29 – 1911.31.)

<u>*Hearing Testimony*</u>

On cross-examination, Duke Witness Snider acknowledged several facts relating to the Company's use of futures contracts and swap contracts to project gas prices. He acknowledged, as stated in his testimony, that natural gas swap contracts are made with financial institutions, not gas suppliers. These are financial instruments that do not involve the physical delivery of gas and they do not actually obligate the Company to purchase any natural gas. (Tr. p. 1628:21-1629:19, 1633:8-23, 1644:2-12.) These financial instruments are not traded on exchanges and their pricing is not public. (Tr. p. 1635:9-25.) Mr. Snider could not identify any other utility that purchases 10-year swaps for natural gas. (Tr. p. 1645:11-23.)

Importantly, Mr. Snider acknowledged that the Company's use of 10-year swaps to project natural prices was driven exclusively by concern over the avoided cost rates paid to QFs under long-term PURPA contracts. (Tr. p. 1648:25-1649:5.) Mr. Snider acknowledged that Duke's sister utilities in Florida, Ohio, Indiana, and Kentucky do not use this approach to gas forecasting because "They do not have the same PURPA structure we have." (Tr. p. 1647:9-14.) Mr. Snider also testified that the use of three years of forward contract pricing, followed by a shift to fundamental forecasts, is a more standard approach to projecting gas prices in the utility industry. (Tr. p. 1648:10-15.)

Although Mr. Snider testified at the hearing that he did not think Mr. Lucas's recommended approach to gas forecasting (using 18 months of market based prices, an 18-month tradition period, and fundamentals based forecasts after that) was reasonable (Tr. p. 1644:7-1645:1), he acknowledged that this is the approach that Duke's sister utility Dominion Energy North Carolina takes with respect to price forecasting. (Tr. p. 1667:8-17; H.E. 43.) Furthermore, Hearing Exhibit 44 indicates that Mr. Snider testified to the North Carolina Utilities Commission that Dominion's approach to forecasting would be reasonable for IRP purposes. (H.E. 44.)

Commission Conclusions

The Commission commends the Duke companies for their substantial progress in reducing reliance on coal; however, the Commission finds the testimony of Witness Lucas and ORS Witness Hayet persuasive and finds that Duke's natural gas forecasting methodology, as set forth in the IRPs, risks reversing much of that progress by over-committing the companies to natural gas generation as a result of artificially low forecasts of gas prices.

The Commission also finds that Duke's IRP modeling and gas-dependent buildout are inconsistent with Duke's internal goals. While Duke states that, "[a]ll portfolios keep Duke Energy on a trajectory to meet its near-term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050," the Commission notes that will be difficult to accomplish with the amount of natural gas capacity DEC and DEP plan to build in the planning horizon. Such gas dependency presents substantial risk.

If natural gas is in fact the most economical and prudent generation technology, Duke must demonstrate that fact in an IRP not skewed by the improper assumptions noted by Mr. Lucas. The ORS's concerns echo his criticisms, even if the ORS is willing to accept the methodology until the next update.

The Commission therefore accepts the recommendations of CCEBA Witness Lucas, and directs that Duke revise its IRPs after revisiting its natural gas pricing methodology and remodeling its portfolios using resulting natural gas price predictions. In its revised IRPs, Duke may not assume firm fuel transport for natural gas CC units at the same price as is currently available. The risk of transport, including pipeline rejections, should be accounted for in a revised IRP. Further, Duke should account for the risk of non-available firm fuel for CT units during peak winter mornings and evenings when building heating load is highest.

The Commission also rejects Duke's use of forward contract prices and swap prices to project natural gas prices for more than three years. It is evident from the testimony of Mr. Lucas and the cross-examination of Mr. Snider that the OTC swaps on which Duke bases its forecasting for most years are non-public financial instruments, individual to Duke, which are entered into by Duke for the sole purpose of establishing price forecasts for avoided cost proceedings. Given the bespoke nature of these instruments and the fact that Duke is the sole purchaser of them, the Commission is not persuaded that there is a robust or "liquid" market for ten-year gas swaps.

Moreover, Mr. Snider acknowledges that these contracts are driven entirely by the company's concerns about the rates paid under long-term PURPA contracts, and that no other utility uses them for resource planning purposes. Even assuming the legitimacy of these concerns about long-term PURPA contracts, there is simply no reason for them to drive Duke's resource planning decisions, and all of the other planning decisions (including, for example, assessments of the value of DSM and EE programs) that derive from the resource plans. To allow the "tail to wag the dog" in this way would distort Duke's planning processes and not be in the interest of ratepayers.

Duke is directed to remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts, as recommended by Mr. Lucas. Finally, Duke should adjust its high and low-price scenarios to reflect the 25th and 75th percentile results to reduce price volatility.

3. Solar Cost Assumptions

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDING OF FACT NOS. 16 - 18

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in these dockets of ORS Witnesses Anthony Sandonato and Philip Hayet, CCEBA Witness Kevin Lucas, Duke Witnesses Glen Snider and Matthew Kalemba, and the entire record in this proceeding.

The ORS Report observed that the LCOE assumed by Duke for the cost of generic solar resources was far higher than the average price of $38/MWh at which DEC and DEP procured solar resources through a competitive solicitation. The Report questioned "whether the utility's assumed revenue requirement for a solar resource is the only solar resource option assumption that should be evaluated in an IRP," and recommended that the Companies include an additional solar generic resource option in their IRP modeling "that reflects the kind of solar PPA prices that may be available in the market." (H.E. 24, ORS DEC Report at 73 (Recommendation No. 18).) ORS recommended that this be implemented in a modified IRP. *Id*.

ORS Witness Philip Hayet elaborated on this recommendation in his direct testimony, stating that Duke's procurement of solar at an average price of $38/MWh in the recent CPRE program constitutes "clear evidence that solar PPA prices can be considerably lower than the cost that Duke Energy can build solar resources for, and indicates that both utility solar and solar PPA options should be modeled in the optimization analysis." (Tr.

p 856.19:10-20.) Mr. Hayet recommended that Duke include a generic solar resource option in its IRP at an assumed cost of $38/MWh. (Tr. pp. 856.19:20–20:2.)

CCEBA Witness Lucas, in his direct testimony, similarly recommended that Duke allow the addition of new resources or PPAs even when there is not a capacity need, as the Commission required of DESC in Order No. 2020-832. (Tr. p. 501.9.) Mr. Lucas noted that in Order No. 2020-832, the Commission found that DESC improperly failed to consider the addition of new resources or PPAs when there was not a capacity need and failed to recognize the potential for energy-only resources to provide savings compared to the running costs of existing resources; consequently, the Commission required DESC to model the procurement of solar energy resources through PPAs in the near-term. (Tr. p 501.19.) Mr. Lucas testified that Duke had "commit[ted] the same error" as DESC, and recommended that Duke be required to include energy-only PPAs as a resource option in the IRP. *Id.*

In his rebuttal testimony, Duke Witness Snider took issue with some aspects of ORS's and CCEBA's recommendations. Mr. Snider agreed with Mr. Lucas that it was appropriate to consider procuring solar as an energy-only resource even in the absence of a demonstrated capacity need. (Tr. p 1586.120:15-24.) However, Mr. Snider argued that it would be inappropriate to model the addition of solar resources via PPAs, because this would "create an unequal and unfair comparison among generation resource options" in Duke's model. (Tr. p. 1586.122:18-19.) This is because "the cost of the [solar] PPA option only represents the costs for the first 20 years of the asset," and it "is not possible to know the cost of that PPA option over the 30-year useful life of the facility," and the developers of solar PPA resources might expect additional revenues after the end of an initial

PPA. Mr. Snider further testified that customers might be exposed to cost risk after the end of an initial 20-year PPA, in the event a CO_2 tax or some other form of climate policy is enacted over the initial 20-year period, resulting in higher PPA prices in the future. (Tr. p 1586.122-123.) Witness Snider acknowledged that DESC had included 20-year solar PPAs as a resource option in its IRP, but stated that "it is unclear why DESC found it methodologically appropriate" to do so and argued that the Commission's DESC order was not relevant because "the Companies are not similarly situated to DESC, whom the Commission found did not use industry-recognized capacity expansion modeling software in preparing its 2020 IRP[.]" *Id.*

On surrebuttal, ORS Witness Hayet testified that he did not find Mr. Snider's objections persuasive. He testified that "a simple means to assuage Mr. Snider's concern" about revenue requirements after the end of a 20-year PPA "would be to model the assumed cost of a 30-year PPA in addition to the cost of the self-built solar resource option." (Tr. p 2307.25:4-6.) Mr. Hayet also noted that in comments filed in avoided cost proceedings under Act 62, the Companies provided a source for 30-year solar PPA prices, and noted that prices close to $38/MWH have been available to it and its regional neighbors. (Tr. p 2307.25:7-14.) Based on this information Duke argued in those proceedings that long-term PPAs for solar resources below $40/MWh could be available in the market. Again, this price is far below the Companies' assumed LCOE for solar resources in the IRP. Given the existence of these lower-cost options, Witness Hayet testified that the "failure to model at least one additional option is not in the best interest of customers." (Tr. p. 2307.26:1-7.)

Like Witness Hayet, Witness Lucas testified in surrebuttal that "there is no reason that 20-year PPAs cannot be evaluated as a resource option," noting that the Companies'

IRPs already model other resources with different lifetimes. (Tr. p. 1911.43:12-17.) Mr. Lucas testified that if a 20-year PPA were to end during the modeling period, the model would evaluate at that time what the most economic replacement resource would be, *Id.*, and it would be entirely speculative to assume that at the end of a PPA the Companies would be obligated to continue to procure energy from those same resources. (Tr. p. 2307.44.) Furthermore, to the extent that a CO2 tax or other carbon price were imposed in the future, "then Duke's customers will already be paying it whether or not the PPA is renewed" and it could be included in the model. (Tr. p. 2307.44:16-18.)

At the hearing, Witness Snider testified on cross-examination that he did not believe that the Companies had an obligation in the IRP process to consider whether it would be possible, and in the interest of ratepayers, to procure solar resources competitively at a cost lower than the Companies' own cost of capital. (Tr. pp. 1678:8–1679:2.) He also testified that he did not think it was appropriate to include third-party solar procurement at prices similar to the CPRE average price of $38/MWh (as recommended by ORS) because he did not think that those results were "repeatable." (Tr. p. 1698.) Although Mr. Snider agreed that it would be appropriate for the Company to conduct sensitivities to assess the impact of being able to procure solar at different market prices, he acknowledged that the Companies had not included any such sensitivities in the IRPs. (Tr. p. 1694-95.)

Witness Hayet testified on cross-examination that he disagreed with Witness Snider's opinion that it was inappropriate to include third-party solar in the IRPs because he was not certain that it could be procured at prices similar to those achieved in recent procurements. (Tr. p 2311-2312.) In Witness Hayet's opinion, Duke "ought to be reasonably certain" based on recent procurement results that it could obtain that pricing. It could alleviate any uncertainty by including sensitivities at higher and lower prices. *Id*. Mr. Hayet also observed that Duke could have "surveyed the marketplace" for more information about pricing, and could have relied on that information in its IRP. (*Id*.) In short, Mr. Hayet could see no reason why Duke should be unable to include solar PPAs in its optimization model. (Tr. p 2314.)

On cross-examination, Duke Witness Kalemba testified about how the Company's modeling handled the issue of expiring PPAs with regard to solar resources "forced into" the model. This category of solar resources includes existing PURPA PPAs, and solar projects procured through the CPRE and GSA programs (which may have PPAs of 20 or 10 years). Mr. Kalemba testified that Duke's model assumes that when those PPAs expire, they are replaced with "like kind" PPAs at identical rates. (Tr. p 1388:3-18, 1394:4-1396:18.) Mr. Kalemba acknowledged that with respect to those solar PPAs, the Company did not see any need to make assumptions about the facilities' post-PPA revenue expectations. (Tr. p 1396:19-23.)

Commission Conclusions

The Commission finds persuasive the testimony of ORS Witness Hayet and CCEBA Witness Lucas that it was unreasonable for Duke not to model additional solar resources at prices representative of those actually obtained by Duke through its competitive solicitations. As Mr. Hayet testified, and as Duke noted in its own filings in its avoided cost dockets, Duke and other utilities in the region have successfully procured solar resources at prices as low as $34/MWh in the recent past. The average price for successful bids in CPRE Tranche 1 was $38/MWh. And although Tranche 2 had not been completed at the time the IRP was prepared, the IRP's description of the preliminary results from Tranche 2 states that the utilities were successful in meeting their procurement targets, and that "The 12 projects selected in Tranche 2 have an estimated savings versus avoided cost of $ 103 million over the 20-year contract term." [DEC IRP Attachment II, Duke Energy Carolinas & Duke Energy Progress Competitive Procurement of Renewable Energy (CPRE) Program Update at 8.] This evidence provides more than adequate assurance that there is a robust market for independently-produced solar resources in the Carolinas, and that such solar resources could be procured at a cost significantly below the Companies' assumed LCOE costs.

Given the parties' general agreement that the competitive procurement of renewable resources could result in savings to ratepayers (even in the absence of a demonstrated capacity need), it is unreasonable for the company not to consider that option in its resource planning. It is telling that the Base Without Carbon scenario (which the Company intends to use for most planning purposes) does not select <u>any</u> additional renewable resources other than those the Company is already either committed or obligated to procure under existing programs like CPRE and GSA. (Hearing Tr. Vol. 6 at 1600:19-1601:6; 1602:7-9, 1603:11-21.) As Mr. Hayet noted, including third-party PPAs as a selectable resource option would not guarantee the selection of solar in the IRP, but would lead to a more accurate result and potential savings for ratepayers. (Tr. Vol. 7 at 2315:12-22.)

The Commission finds unpersuasive Mr. Snider's objection that including solar PPAs as a resource option would create an unfair "apples-to-oranges" comparison in the IRP. As Mr. Lucas observes, the Company already includes resources with different expected lives in its resource plans. Nor does the Commission accept the claim that the post-PPA revenue expectations of third-party project developers impose risks on ratepayers. It is entirely speculative to assume that the Company would have any financial obligation to those third-party providers at the end of a 20-year PPA. It is also inappropriate for speculation about potential future carbon pricing to drive modeling decisions in the Base Without Carbon plan, given that that scenario assumes no such costs will be imposed. Even if there were serious concerns about post-PPA revenue requirements, the Company could address those concerns by assuming 30-year PPAs. On this issue the Commission also notes Mr. Kalemba's admission that Kalemba, Duke modeled the expiration of PPAs for solar resources "forced in" to its model (including already contracted PURPA projects, CPRE projects, and GSA projects) without difficulty, by assuming that those PPAs would be extended indefinitely at the same cost. (Tr. p. 1394:4-11.)

In light of this evidence, the Commission will direct the Companies to include generic third-party solar resources as a selectable resource in a Modified IRP and IRP Update. As a proxy for market prices, Duke shall assume pricing of $38/MWh. Duke shall include sensitivities in the modified IRP for PPA pricing at $36/MWh and $40/MWh. For purposes of modeling solar PPAs as a selectable resource, the Company shall assume a contract term of at least 20 years, and operational characteristics identical to CPRE projects (such as the limited dispatchability as provided for in CPRE contracts).

4. Solar Operational Assumptions

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 19 - 20

Summary of the Evidence

The evidence in support of these findings of fact is found in the testimony and exhibits of CCEBA Witnesses Arne Olson and Kevin Lucas and Duke Witnesses Matthew Kalemba and Glen Snider.

Effect of ITC on Modeling

In his direct testimony, CCEBA Witness Kevin Lucas testified that the recent passage of the Federal Investment Tax Credit ("ITC") "offers a chance to more economically deploy solar and solar plus storage projects prior to 2025 to jumpstart Duke's progress towards its goals." (Tr. p. 501.24:19-21) Lucas testified that because the Duke IRPs "backload" the renewable capacity additions in favor of natural gas early in the plan, it misses the opportunity to allow more economical investment in solar and solar plus storage in the first two years of the plan to the benefit of its customers. (Tr. p. 501.31:16-19.)

Witness Lucas testified that prior to December 2020, the ITC was in the process of being phased out, but Congress passed legislation extending the step-down by two years at a 26% credit for projects commenced before December 31, 2022 and a 22% credit for those commenced by December 31, 2023. In addition, the "safe harbor" provision was extended, allowing developers to lock in the credit for up to four years based on the commencement of construction so long as the project is in service by December 31, 2025. (Tr. p. 501.33:11-17.) Lucas stated that for projects coming online in 2022 and 2023, the extension could provide a $3-4/MWh reduction in levelized cost, pushing solar costs into the low-$20s per MWh, making solar even more competitive for new generation. (Tr. p. 501.35:1-4.)

Despite the fact that the extension of the ITC was passed after the development of the 2020 Duke IRPs, "it is of sufficient scale and consequence" that Lucas recommended that Duke update its modeling to account for the change. (Tr. p. 501.31:19-21.) Duke's assumption regarding the ITC, Lucas testified, may have been reasonable at the time the IRP was filed, but Lucas notes that the Commission is required by Act 62 to determine whether a plan is the most reasonable and prudent "as of the time the plan is reviewed." (Tr. p. 501.35:16-18.) Lucas recommended that Duke update its modeling to account for the opportunity allowed over the next 2-5 years as a result of the ITC extension.

In his rebuttal testimony, Witness Kalemba took issue with Lucas's recommendation, stating that because the ITC extension came after the IRP was prepared, it was proper to consider the IRP on its merits and address the effect of the ITC extension during the next annual update. Kalemba maintained that it would be impossible to adjust the IRP for every change that occurred subsequent to its submission. (Tr. pp. 1382:2-18; 1390.7.) He therefore recommended against adjusting Duke's modeling and assumptions until the 2021 update or later.

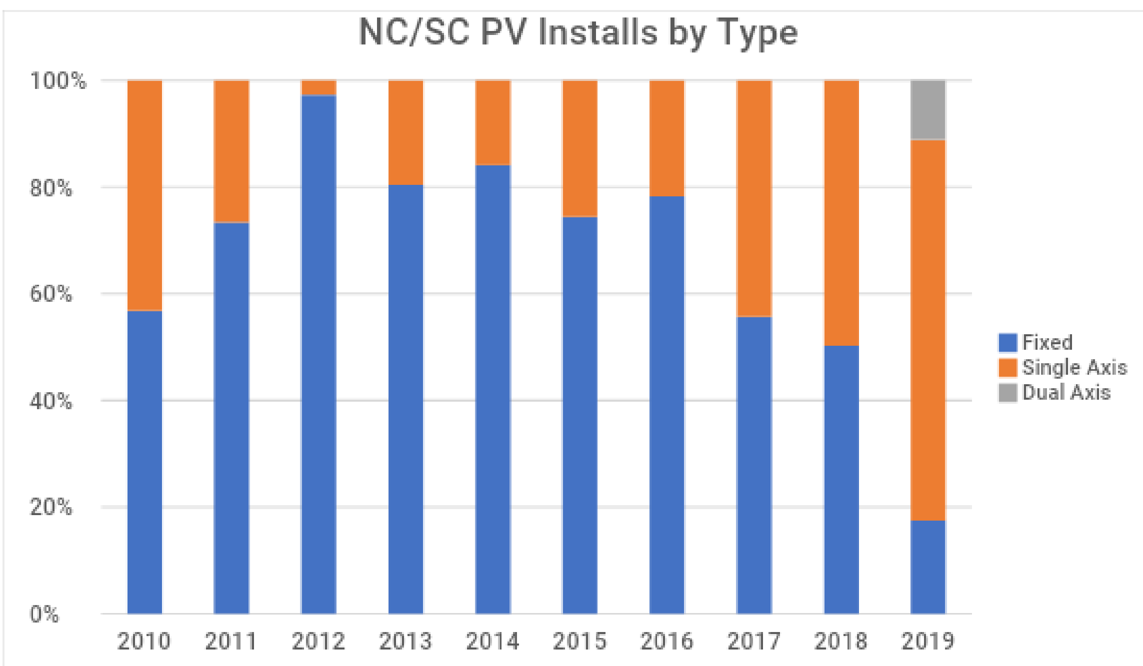
Assumption of Fixed Tilt Solar vs. Tracking

Witness Olson testified that solar projects can be either fixed-tilt or tracking. "Fixed-tilt solar arrays remain fixed, whereas tracking solar arrays move throughout the day to maximize exposure to solar radiation." (Tr. pp. 485.25:22 – 485.26:1.) Olson noted that the price for tracking solar has dropped to be essentially equivalent to that of fixed systems, and that it is "highly likely that new solar projects constructed in Duke's South Carolina and North Carolina service territories will use tracking systems rather than fixed-tilt." (Tr. p. 485.26:7-13.)

Despite that, Olson noted, Astrapé assumed that 40% of future solar is fixed-tilt and 60% of future solar is single axis tracking. (Tr. p. 485.26:3-5.) Olson testified this assumption is inappropriate and not supported by the state of the industry, and recommends that Duke model all new installations at 100% tracking, which should result in a higher ELCC value for solar in the modeling. (Tr. p. 485.27:13-15.)

Witness Lucas also addressed the issue of tracking solar, recommending that Duke "update its assumptions on future builds of solar to be 100% single-axis tracking systems for large projects and at least 80% single-axis tracking systems for future PURPA projects." (Tr. p. 501.7:8-10.) Lucas testified that "over the past decade, there has been a steady shift from fixed-tilt projects to single-axis trackers that has corresponded to a decrease in the price premium of tracking hardware. Under today's economics, the benefit from added production outweighs the higher cost of tracking hardware, making it an economic decision to install trackers in most locations." (Tr. p. 501.47:17-20.)

Witness Lucas presented a chart showing the trend towards tracking systems in the Carolinas (Tr. p. 501.48 (Fig. 7)):



Lucas also testified to the "notable" difference in production between single-axis and tracking, noting that "tracking systems climb to their peak output earlier in the morning and maintain their generation levels later in the afternoon, leading to the systems producing 19% more energy in total than fixed-tilt systems. (Tr. p. 501.48:11 – 501.49:3.) Lucas then testified that Astrapé assumed that of the 7 GW of solar deployed only 16% would be single-axis. Lucas noted that this limitation is inconsistent with the actual build of solar in the Carolinas since 2019. (Tr. p. 501.50:7-12.) As a result, Lucas testified, Duke undercounts the capacity benefit of solar significantly, particularly in the winter. (Tr. p. 501.52:4-11.) Finally, Lucas noted that Duke's assumption that 100% of PURPA projects would be fixed-tilt is not accurate. (Tr. p. 501.54:13-20.)

As a result, Lucas testified, Duke's assumption "negatively affects the economics of solar and solar plus storage facilities in the Company's modeling." (Tr. p. 501.57:5-6.) Lucas then recommended that Duke perform an analysis to determine the current mix between tracking and fixed systems among PURPA solar facilities in DEC and DEP territories, or use the latest data from EIA Form 860, and then adjust its assumptions on replacement of these projects by "recognizing the shift towards tracking that is occurring . . . I recommend an assumption that at least 80% of new PURPA projects be assumed as single-axis tracking based on an extrapolation of 2019 data and that Duke incorporate this into its assumption of replacement capacity from existing PURPA projects." (Tr. p. 501.58:14-23.) He further recommended that Duke "assume 100% of future designated and mandated builds be assumed to be single-axis trackers." (Tr. p. 501.59:1-5.)

Duke witness Roberts, on cross-examination, stated that he agreed that the transition to single-axis tracking should be taken into account in modeling. (Tr. p. 1078:8-

20.) Roberts, however, differed with Lucas on the effect of single-axis tracking systems in the Carolinas, testifying that in the Carolinas, most systems are on a north-south axis and "with north-south axis – single axis tracking solar, you actually get less energy in the winter as to what you could get with east-west tracking solar." (Tr. p. 1079:10-19.)

Commission Conclusions

Based on the testimony and evidence received, the Commission agrees with Witness Lucas that the ITC extension, if incorporated into the Duke's solar and solar plus storage modeling, would have a measurable and significant effect on the competitiveness of solar in the initial few years of the IRP planning period. Because it is a finite extension, not including it in the initial modeling may result in less solar and solar plus storage being built than would otherwise. Therefore, it is reasonable to require Duke to adjust its models to account for the effect of the ITC extension on solar development.

Further, the Commission concludes that the transition to single-axis tracking hardware in solar development projects is obvious and significant, and finds that Duke has underrepresented such systems in their assumptions for modeling both solar construction and solar capacity benefits. It is reasonable therefore to require Duke to adjust its modeling as suggested by Witness Lucas.

5. Battery Storage Pricing Assumptions

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 21

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony and exhibits in this docket of CCEBA Witness Kevin Lucas, Duke Witness Matthew Kalemba, and the entire record in this proceeding.

Duke Witness Kalemba describes in his direct testimony Duke's process for selecting the pricing assumptions for battery storage in the IRPs. (Tr. p. 325.18.) Witness Kalemba describes the use of third-party cost projections for battery storage, including the National Renewable Energy Laboratory's 2020 Annual Technology Baseline (ATB), Lazard's Levelized Cost of Storage, and Pacific Northwest National Laboratory's Energy Storage Technology and Cost Characterization Report. (Tr. p. 325.18.) Witness Kalemba states that due to "disparate definitions and incomplete documentation," this benchmarking identified several areas of potential discrepancy, and as a result, Duke made "several adjustments" to its battery cost input assumptions. These primarily included assumptions regarding the degradation of battery cells and depth of discharge assumptions. (Tr. p. 325.18-19.) Witness Kalemba also discussed the expected battery storage price declines that Duke incorporated into its IRPs. (Tr. p. 325.20.)

CCEBA Witness Lucas responds in his direct testimony to Duke's assumptions regarding battery storage prices. (Tr. p. 501.42.) Witness Lucas states that Duke admits that its battery storage prices "appear higher than published numbers" but that in an attempt to explain these discrepancies Duke refers to differences related to depth of discharge, interconnection costs, software and control costs, equipment expenses, and Duke's lack of experience with energy storage. (Tr. p. 501.42.) Witness Lucas discusses the ways in which the third-party cost projections accounted for depth of discharge and battery degradation and explained that Duke's assertions that these third-party sources were inconsistent or difficult to reconcile were not correct. (Tr. p. 501.43-44.) Witness Lucas also critiques Duke's assumption regarding O&M costs for batteries and assumption that 100% of the battery must be replaced midway through the 30-year life. (Tr. p. 501.45-46.) Witness

Lucas notes that the assumption regarding 100% replacement was inconsistent with other Duke assumptions that they would overbuild batteries to account for depth of discharge and degradation, and therefore for Duke to completely scrap the battery after 15 years despite its sizable remaining capacity is inconsistent with Duke's own assumptions. (Tr. p. 501.47.) Witness Lucas also notes that Duke inappropriately makes this replacement only 12 years into the battery's life rather than the appropriate 15 years. (Tr. p. 501.47.) Witness Lucas concludes that Duke's battery storage cost estimates are substantially higher than other benchmarks and recent RFI results and recommends that, as the Commission found in the DESC IRP proceeding, Duke be required to remodel its IRP using the NREL ATB's Advanced/Low scenario. (Tr. p. 501.48.)

Duke Witness Kalemba responds in rebuttal testimony to the testimony of Witness Lucas, asserting that the NREL ATB cost estimates recommended by Witness Lucas are not appropriate for long-term planning. (Tr. p. 1390.10.) Witness Kalemba states that "it is becoming increasingly difficult to rely on published resources to justify battery costs for long-term planning purposes." (Tr. p. 1390.15.) Witness Kalemba expresses the concern that published battery costs might not be "robust enough" to meet the needs of the Companies' system. (Tr. p. 1390.16.) Witness Kalemba describes the changes that different assumptions make to the assumed battery storage costs, and he states that NREL only normalizes costs to develop cost projections. (Tr. p. 1390.17-18.) Witness Kalemba states that he does not believe it is appropriate to rely exclusively on the NREL ATB for energy storage pricing. (Tr. p. 1390.22.) Witness Kalemba testifies that it is appropriate for Duke to "overbuild" storage in its model and replace the entire battery after 15 years. (Tr. p. 1390.23-24.) Witness Kalemba also identifies an error in Duke's calculations relating to the O&M costs of battery storage, which he indicates that Duke will correct in the 2021 IRP Update. (Tr. p. 1390.27-28.)

CCEBA Witness Lucas responds in his surrebuttal testimony to Duke Witness Kalemba. Witness Lucas rebuts Witness Kalemba's assertion that the published battery costs would not be robust enough for the Company, stating that Duke has provided no support for this statement and does not justify spending substantially more money on batteries based on this vague and unsupported standard. (Tr. p. 1912.49-50.) Witness Lucas also testifies that Duke should not assume that all new battery storage will be installed in greenfield locations therefore incurring additional siting and interconnection costs. (Tr. p. 1912.50.) Witness Lucas also rebuts Witness Kalemba's assertion that Witness Lucas "cherry-picked" data in his direct testimony, clarifying that he simply reported the prices provided by the sources Duke had already reviewed. (Tr. p. 1912.50.) Finally, Witness Lucas reiterated his initial recommendation that Duke use the NREL ATB Low figures, consistent with the Commission's directive in the DESC IRP proceeding. Witness Lucas also recommended that the Commission order Duke to issue an RFI for battery storage projects to provide better pricing information for the next IRP Update and future IRPs. (Tr. p. 1912.51.)

Commission Conclusions

The Commission agrees with Witness Lucas that Duke's battery storage cost assumptions are unreasonably high and that Duke should instead use the NREL ATB Low figures for its battery storage cost assumptions. The NREL ATB Low figures appropriately account for depth of discharge and degradation, and these figures represent a reasonable assumption for battery storage costs for use in the IRPs. Duke should use these ATB Low figures in its Modified IRP and future IRP proceedings.

6. Assumptions Regarding Interconnection Limitations

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 22 - 24

Summary of the Evidence

The evidence in support of these findings of fact is found in the testimony and exhibits in the dockets of CCEBA Witness Kevin Lucas, Vote Solar Witness Tyler Fitch, Duke Witness Matthew Kalemba, and Intervenor Witness Rachel Wilson.

In its IRPs, Duke limited the amount of solar and solar plus storage that could be interconnected in any year to 500 MW (split 300 MW in DEC and 200 MW in DEP) in the base cases and 900 MW (split 500 MW in DEC and 400 MW in DEP) in the high renewable cases. (Tr. p. 501.60:9-12.)

Witness Fitch testified that Duke's assumptions regarding the rate of interconnection of solar and solar plus storage are fundamentally flawed and "apply conservative assumptions to solar interconnection that curtail consideration of cost effective renewables." (Tr. p. 732:12-15.) Mr. Fitch testified that the conservative assumptions in the IRP unduly limit the integration of solar and solar plus storage: "the Companies assumed that maximum solar deployment per year was the same as the historical average in the base case, despite noting the potentiality of ISOP [Integrated System and Operations Planning] to accelerate interconnection, citing increased pace of interconnection as a 'key element' for meeting zero-carbon goals, and pursuing interconnection queue reforms outside of this proceeding. Based on the Companies' stated intention on improving the pace of interconnection, Companies should increase the upper solar interconnection limit." (Tr. p. 736.64:3-9.)

CCEBA Witness Lucas testified that Duke's IRPs fail to reflect Duke's true capability to interconnect solar and solar plus storage. According to Lucas, this capability is not speculative, because Duke has already demonstrated its ability to interconnect large quantities of solar resources. In 2015 and 2017, respectively, Duke interconnected 718 MW and 744 MW of solar across its Carolinas service territories. Its highest single year in the DEC territory was 190 MW in 2016, and its highest year in the DEP territory was 633 MW in 2017. (Tr. p. 501.61:1-3.) Moreover, Lucas stated, during those years Duke was interconnecting a large number of small projects; since then, the market has shifted towards a smaller number of large projects. (Tr. p. 501.61:6-12.) Accordingly, Lucas testified that Duke should be capable of interconnecting significantly more solar and solar plus storage capacity than it historically has, given this shift in project size as well as the reforms made to Duke's interconnection process. *Id.* Witness Lucas recommended that the Commission require Duke to revise its IRPs by raising the interconnection limitation from 500 MW in the base cases to a higher number, referring to the Synapse Report presented by Witness Rachel Wilson as an example of the portfolio that could be produced if the interconnection limits were increased. (Tr. 501.62:6-9; Tr. pp. 2000:5 - 2001:1.)

Duke Witness Kalemba agreed in his rebuttal testimony that "[f]rom 2014 through 2019, nearly 3,200 MW of utility scale solar was added to the Companies' systems, resulting in approximately 3,500 MW (2,750 MW DEP and 750 MW DEC) of utility-scale solar (greater than 1MW) interconnected and operational in DEP and DEC at the end of 2019." (Tr. p. 325.4:5-9.) Kalemba stated that "given the saturation of solar on the DEC and DEP systems, maintaining the pace of interconnecting new solar at the rate of the 2017 time period will be challenging." (Tr. p. 1390.36:14-16.)

Witness Kalemba emphasized on cross-examination that Duke's optimizer model limits the amount of new generation that can be put on Duke's system each year due to interconnection constraints and that the company was "limiting to 500 megawatts annually." (Tr. pp. 1422:8-12; 1423:4-6.) Witness Kalemba stated that this constraint was necessary, because "the 500-megawatt constraint that we're talking about is what we feel like we can consistently add every year. It is true that we have done better than that in the past. We've done a lot worse in the past." (Tr. p. 1430:13-18.) According to Witness Kalemba, these limits reflect "the physical and timing constraints that we're experiencing." (Tr. p. 1431:7-10.) However, Mr. Kalemba acknowledged that he did not specifically know why Duke's interconnection performance was much lower in 2018 and 2019, and also could not say whether that performance reflected a long-term trend or only a short-term constraint that could be resolved. (Tr. p. 1439:11-20.)

On further cross-examination, Kalemba admitted that the 500-megawatt interconnection limitation applies only to renewables and storage, and not to any other generation technology, including natural gas, stating "[i]t's just solar." (Tr. p. 1424:9-15.) He later added that Duke applied a separate 150 MW per year interconnection limitation to wind resources. (Tr. p. 1425:21-23.) Kalemba testified that Duke did not need to add the same restraints to a CT plant, for instance, because such installations are "planned well in advance" and "sited in places that are maybe less interconnecting restrained [sic]. We just don't see the same issues with these generators." (Tr. pp. 1424:18 – 1425:3.) Kalemba also noted that solar installations require "a lot of land," which is difficult to find close to transmission. (Tr. p. 1425:3-7.) Mr. Kalemba also acknowledged that because renewable resources already "forced in" to Duke's model counted towards the 500 MW annual limitation, this constraint effectively prevented the model from selecting any new renewable resources until at least 2025. (Tr. p. 1427:19-1428:18, 1429:5-24.)

Mr. Kalemba nevertheless admitted that a gas interconnection request would "be subject to the same physical constraints and the same study constraints that any other interconnection request would be subject to." (Tr. p. 1432:4-21.) He further acknowledged that Duke had informed this Commission that queue reform efforts would "reduce the number of speculative projects entering the queue and will enable the companies to more timely, fairly, and efficiently process new interconnection requests." (Tr. p. 1435:6-13.) He also agreed that Duke had informed the Commission that "the Companies' queue reform proposal will help achieve Act 62's goals of fashioning generator interconnection procedures that allow for a continued transition to higher penetrations of distributed energy resources, while ensuring the generator interconnection process is efficient, fair, reasonable, and non-discriminatory for all customers." (Tr. pp. 1436:10 - 1437:2.) He further acknowledged on cross examination that it would be illegal for Duke to favor its own generation assets over others in interconnection. (Tr. p. 1433:9-14.)

In surrebuttal, CCEBA and CCL *et al.* presented the testimony of Witness Rachel Wilson, including the Synapse Report attached to her testimony as Exhibit RSW-2. (H.E. 56.) In its "reasonable assumptions" modeling, Synapse used much higher interconnection limits. Between 2021 and 2026, Synapse modeled an additional 3,100 MW of new renewable capacity, rising to 9,000 MW from 2027 through 2031. (H.E. 56 [Exhibit RW-

2, p. 1].) The resulting modeled portfolio contained significantly more renewable resources than any of the Duke cases.

Commission Conclusions

While the Commission accepts Mr. Kalemba's claim that physical and technical restraints on interconnection justify *some* limitation on the scope and scale of additions of new resources in Duke's modeling, a 500 MW annual limitation on the interconnection of renewables throughout the planning period is not reasonable, in light of Duke's demonstrated ability to interconnect greater amounts of generation in past years, the implementation of queue reform, and technical advancements in recent and coming years. The Commission agrees with witness Lucas that a reasonable and prudent IRP would reflect increases in the amount of interconnection over and above the 500 MW cap established by Duke in its base cases. The Commission further notes that Duke's ability to interconnect new resources is not entirely out of its control -- it has the ability not only to improve its process (as evidenced by its Queue Reform initiative) but also to make investments in its own interconnection capacity, if such investments would be in the interest of ratepayers.

The Commission further notes that the Duke IRPs themselves anticipate some portfolios with significantly more interconnection of renewable resources than 500 MW. Moreover, the Commission agrees with Intervenors that Duke's explanation for why anticipated new natural gas and other non-renewable resources are not so limited is not persuasive. Duke is prohibited by law from favoring its own generation assets in interconnection.

There is insufficient evidence in the record to determine at this time what the "correct" limitation on annual interconnections is. Accordingly, the Commission will require Duke, in its next full IRP, to provide a limitation on interconnection capacity that is analytically justified, nondiscriminatory, and accounts both for the expected benefits of queue reform and the possibility of making further investments in the Companies' capacity to study and interconnect new generation. The Commission encourages Duke to consider whether alternatives to a flat annual limitation might be more appropriate, and to engage Interconnection Customers and other stakeholders in discussions on this issue.

In the interim, for purposes of the Modified IRP and IRP Update, the Commission will require Duke to assume a 750 MW annual limitation on the interconnection of solar and storage resources, which is approximately equal to Duke's highest annual performance in recent years.

G. Portfolio Modeling and Scenario Analysis

1. Risk assessment and plan evaluation

a. Duke's flawed risk methodology and application of minimax regrets analysis

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 25

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony and exhibits in these dockets of CCEBA Witness Kevin Lucas, Duke Witness Glen Snider, ORS Witness Lane Kollen, and the entire record in this proceeding.

CCEBA Witness Lucas testified that Duke failed to perform sufficient risk analysis in the preparation of the IRPs. (Tr. pp. 501.7, 501.29.) Witness Lucas testified that, by conducting only a qualitative rather than quantitative risk analysis, Duke failed to produce analyses to compare its portfolios across various input assumptions. Id. Witness Lucas recommended the use of a "minimax regret analysis" on Duke's IRP scenarios, which is a straight-forward analysis that provides insight about how portfolios may perform under a variety of future scenarios. A minimax regret analysis highlights the importance of looking beyond a portfolio that is assumed to be least-cost in limited scenarios. (Tr. pp. 501.29-30.) The analysis recommended by Witness Lucas presents the difference between a portfolio's highest present value revenue requirement ("PVRR") and the lowest PVRR for all scenarios. Witness Lucas performed a minimax regret analysis, which indicated that the Earliest Practical Retirement portfolio was a close second to the Base Case with Carbon Policy scenario. (Tr. p. 501.32.) Witness Lucas noted that the results of his minimax regret analysis still included Duke's flawed assumption regarding natural gas price forecasts and transmission costs, among others, and that by fixing these flaws, a more robust minimax regret analysis would result. (Tr. p. 501.33.)

ORS Witness Kollen also described the risk analysis performed by Duke in its IRPs. (Tr. p. 965.8:17 – 965.9:2.) Similar to CCEBA Witness Lucas, Witness Kollen performed a minimax regret analysis to assess how Duke's portfolios compared to each other. Witness Kollen's analysis produced the PVRR amount by which each portfolio exceeds the lowest cost portfolio in each fuel cost and CO_2 price case. (Tr. p. 965.9.) Witness Kollen concluded through his analysis that for DEC, the Base Plan with Carbon Pricing had the lowest maximum regret result, and for DEP, the Base Plan without Carbon pricing had the lowest maximum regret result. (Tr. p. 965.10.)

In response to the testimony of Witnesses Lucas and Kollen, Duke Witness Snider testified that Duke is willing to adopt a minimax regret analysis to quantify risk of economic analysis results in future IRP and that the Companies "view the use of Minimax Regret Analysis as a useful tool to help distill economic results in a digestible and consumer-friendly summary." (Tr. p. 1586.147.) Witness Snider stated that Duke prefers the minimax regret analysis performed by ORS Witness Kollen, which selected the Base Planning Case without Carbon Policy as minimizing maximum regret. (Tr. p. 1586.148.)

In surrebuttal, CCEBA Witness Lucas testified that it is unclear whether the ORS minimax regret analysis used Duke's PVRR figures with or without the explicit cost of carbon; Witness Lucas testified that he used values with the cost of carbon included because scenarios which included a cost of carbon should be compared including these costs. (Tr. p. 1912.48.) Witness Lucas also noted that while ORS conducted the minimax analysis for DEC and DEP separately, he combined the PVRRs of both Company portfolios because the Companies would very likely be subject to the same type of carbon and commodity pricing. (Tr. p. 1912.49.) Witness Lucas also stated that his approach of comparing the max regret across all scenarios is more appropriate than limiting the regret calculation to a given fuel/CO_2 scenario.

In response to Duke Witness Snider's assertion that focusing only on a given fuel/CO2 scenario is more appropriate, Witness Lucas testified that the entire point of scenario planning is to compare the potential outcomes across multiple potential futures, and in this case, the multiple potential futures are the various fuel/CO_2 combinations, not the various resource portfolios. Id. While ORS Witness Kollen's analysis fixed a given fuel/CO_2 combination and then considered how it would affect multiple portfolios, Witness

Lucas fixed a given portfolio and then compared its performance against multiple fuel/CO_2 combinations relative to the lowest cost combination. Witness Lucas stated that this approach was more appropriate because "[t]he future uncertainty is not what resource mix will be chosen, but rather what fuel/CO_2 combination will occur." (Tr. pp. 1912.49:21 – 1912.50:5.)

Commission Conclusions

The Commission notes that there is consensus among the relevant witnesses that it is appropriate for Duke to use a minimax regret analysis in the development of the Companies' IRPs. The Commission agrees, as it found during the DESC IRP proceeding, that such analysis presents a useful tool to compare and assess the likely riskiness of different resource portfolios in different scenarios. As to the specific minimax regret analysis to be performed by Duke, CCEBA Witness Lucas and ORS Witness Kollen each performed a slightly different variation of the minimax regret analysis. Upon consideration, the Commission finds that the analysis methodology used by CCEBA Witness Lucas is more appropriate and should be used by Duke. The Commission further agrees with Witness Lucas that it is appropriate to conduct the analysis for the combined DEC and DEP territories, and that it is more appropriate to compare the maximum regret across all scenarios rather than limiting the regret calculation to a given fuel/CO_2 scenario. The methodology used by Witness Lucas is consistent with the methodology the Commission adopted in the DESC IRP proceeding, and the Commission believes it is appropriate for both Duke and DESC to apply the same minimax regret analysis methodology. Therefore, for each modified IRP, IRP update, and future IRP, Duke is directed to include a minimax regret analysis of the type used and described by CCEBA Witness Lucas. In doing this analysis, Duke shall use the most recent Commission-approved inputs.

b. Evaluation of Stranded Asset and Climate Risks

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 26

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRPs, pleadings, testimony of Duke Witnesses Dawn Santoianni and Glen Snider, Vote Solar Witness Tyler Fitch, CCEBA Witness Kevin Lucas, and CCEBA and CCL et al. Witness Rachel Wilson, as well as exhibits in these dockets, and the entire record in this proceeding.

Duke Witness Dawn Santoianni, Duke's State Energy Policy Director for North Carolina, testified regarding the IRPs and Duke Energy's climate goals. Witness Santoianni provided a summary of the North Carolina Clean Energy Plan ("NC CEP") process, which resulted after the North Carolina governor issued an executive order directing the North Carolina Department of Environmental Quality to develop a plan encouraging the development of clean energy, including solar, wind, energy storage, energy efficiency, and other technologies, and the modernization of the electric grid to improve resiliency. (Tr. p. 224.5:14-19.)

The NC CEP established a goal to reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050. (Tr. p. 224.6:9-11.) Witness Santoianni attached Duke Energy's 2020 Climate Report as an exhibit to her testimony; she testified that the report summarizes Duke's climate goals and provided an illustrative pathway for Duke Energy to achieve this 2050 net zero goal. (Tr. p. 224.15:6-9.)

Witness Santoianni testified that all of the pathways included in the 2020 IRPs keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon. (Tr. p. 224.16:10-11.) According to Ms. Santoianni, the 2020 IRPs include portfolios with more ambitious carbon emission reduction targets which would require enabling policy; specifically, she testified that all portfolios except the Base Case without Carbon policy would require enabling policy changes. (Tr. p. 224.17:3-6.)

Under cross examination at the hearing, Witnesses Santoianni and Glen Snider admitted that the 2020 Climate Report was "not used in any way in the development of the 2020 IRPs." (Tr. pp. 95:3-5–97:4, 239:10–240:19; H.E. 4.)

Vote Solar Witness Tyler Fitch testified that the Companies' IRPs were deficient due to their failure to comprehensively incorporate and assess risks associated with climate change. Witness Fitch noted that "[c]limate-related risks and opportunities are a critical concern to firms, sectors, economies, and even the global financial and economic system in the 21st century" and that a common framework exists for assessing these risks. (Tr. pp. 736.12 – 736.13.) Citing several examples, Mr. Fitch testified that physical, financial, economic, and regulatory climate-related risks are already having an impact on the electricity sector, and will only continue to accelerate. (Tr. p. 736.14:7-13.) Mr. Fitch prepared a report, titled "Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan" (the "Vote Solar Report"), which assessed the Companies' exposure to climate-related risks and determined that that Companies are exposed to physical, financial, economic, regulatory, and regulatory climate risks, each of which are significant and likely to continue to accelerate through mid-century. (Tr. p. 736.20:1-5.)

In the Vote Solar Report, Witness Fitch also analyzed potential stranded asset risks if the Companies were to pursue their Base Case with Carbon policy scenario and continue to comply with their net-zero carbon commitment. (Tr. p. 736.19:4-8.) Using a high-level economic model, Mr. Fitch found that the stranded asset costs for the Base Case with Carbon Policy alone could total $4.8 billion in 2020 dollars. (Tr. p. 736.7:13-18; H.E. 22 pp. 15-16.) Mr. Fitch testified that such stranded asset risks are often borne by ratepayers rather than utility shareholders. (Tr. pp. 736.25:19 – 736.26:6.)

Finally, Witness Fitch noted an apparent disconnect between the Companies' rhetoric regarding climate risks and their failure to incorporate those risks into their IRPs. (Tr. p. 769:7-12.) While Duke Energy evaluated climate risks in its 2020 Climate Report and publicly announced its 2050 net-zero goal, Mr. Fitch argued that climate-related risks were not systematically analyzed in the IRP. As a result, Mr. Fitch recommended that the Commission reject the IRPs and require the Companies to revise their IRPs to better evaluate and mitigate both short- and long-term climate risks. (Tr. pp. 736.100:15–736.103:9.)

Witness Fitch also recommended that the Commission direct the Companies to provide regular updates on its integrated systems and operations planning ("ISOP") processes and ensure those processes consider physical and transition climate-related risks and the cost benefits of managing those risks. (Tr. 736.56:14-19.) He also recommended that the Companies avoid moving forward with generation, distribution, or transmission investments that could be deferred or displaced by DERs if analytical capabilities were already in place, and that the Commission direct the Companies to develop a 'no regrets' screen to ensure projects that could be cost-effectively displaced are avoided. (Tr. pp. 736.56:20 – 736.57:3.)

CCEBA Witness Kevin Lucas testified that Duke should produce a more robust risk assessment of its proposed buildout of natural gas infrastructure, including risks associated with obtaining firm fuel supply and stranded assets. Witness Lucas noted that, despite Duke's assumption that its natural gas fleet would "shift from providing bulk energy supply to more of a peaking and demand-balancing role," the Companies' Base case portfolios in the IRPs would double the capacity of high capacity factor natural gas combined cycle ("NGCC") units by 2040, with other scenarios adding between 50% and 75% more NGCC capacity. (Tr. p. 501.26:17-24.) Mr. Lucas further noted that much of this new capacity would be added after 2032, only 18 years before the Companies' corporate goal of reaching net zero. (Tr. p. 501.26:23-24.) Mr. Lucas argued that building that much new NGCC capacity with less than two decades until the Companies' planned transition to net zero would risk stranding billions in dollars of assets. (Tr. p. 501.27:2-6.) While Duke did perform a nominal stranded asset sensitivity, it assumed that natural gas units would have a 25-year life; Mr. Lucas questioned this assumption in light of the Companies' net-zero goal and its planned addition of thousands of MW of capacity after 2030. (Tr. p. 501.27:4-5.)

Witnesses Fitch and Lucas both recommended that the Companies evaluate the potential benefits of an energy imbalance market or regional transmission organization within their IRPs. (Tr. pp. 276.63:1-4; 501.106:21-25.)

In rebuttal, Duke Witness Glen Snider took issue with several of the assumptions used in the Vote Solar Report's evaluation of stranded asset risk. In particular, Witness Snider argued that natural gas is a necessary bridge for the Companies to reach their net zero goal and that the Vote Solar Report inflated the cost and risk associated with natural gas while understating its role in ensuring reliability. (Tr. pp. 1586.103 – 1586.105, 1586.109:21 – 1586.110:14.) Duke Energy Witness Roberts similarly testified that Witness Fitch failed to adequately address the Companies' obligations to manage operational risks and meet NERC reliability standards. (Tr. p. 1052.4:12-16.) However, at the hearing Witness Roberts stated that he did not know whether consideration of stranded asset costs would create any conflict with the Companies' reliability obligations under NERC. (Tr. 1131:12– 1140:3.)

Witness Santoianni defended the Companies' use of a 25-year life span for natural gas assets, stating that while those were shorter than what is currently in depreciation schedules, that they were appropriate for today's planning and that natural gas generation was still viable. (Tr. pp. 1536.5:19–1536.6:1) Ms. Santoianni argued that it was not the role of regulated utilities to set climate change standards, and that those issues should be addressed by state or federal lawmakers. (Tr. p. 1536.3:10-13.) Ms. Santoianni also argued that consideration of regulatory and market design changes are legislative issues beyond the scope of the 2020 IRP proceedings. (Tr. p. 1536.22:6-18.)

Finally, in response to Witness Fitch, Duke Witness Mark Oliver argued that Duke was already continuing to develop ISOP in accordance with best practices, and that the Companies planned to incorporate ISOP into its 2022 IRPs. (Tr. pp. 1331.3:21-23, 1331.6:14-15.) He further testified that there are no proven objective approaches for quantifying the cost risks associated with climate change. (Tr. p. 1331.8:7-15.) At the hearing, however, Witness Oliver admitted that he had not personally read the Vote Solar Report. (Tr. p. 1340:25 – 1341:3.)

Witness Fitch responded to the Companies in his surrebuttal testimony, first noting that the Companies methodological complaints ultimately did not rebut the basic finding that carbon-emitting assets would be subject to increased risks, including stranded asset costs. (Tr. p. 742.5:3-6.) Mr. Fitch defended the assumptions and methodologies in the Vote Solar Report as reasonable, and noted that the report's analysis was conducted to address the fact that the Companies seek to build a new fleet of natural gas generation while also committing to a net-zero carbon energy system by 2050. (Tr. p. 742.11:15-19.) He testified that the Vote Solar Report was intended to provide a high-level analysis of the potential risks to ratepayers, which Duke failed to quantify or assess in its IRPs. (Tr. p. 742.12:2-11.)

CCEBA and CCL et al. Witness Rachel Wilson also testified that Duke's reliance on gas in its IRP modeling scenarios places the environmental and financial risks of new gas builds on the Companies' ratepayers. Witness R. Wilson testified that, given the inevitability of carbon regulation, coupled with state carbon-reduction goals and Duke's own corporate goals, investments in gas infrastructure are increasingly at risk of becoming stranded assets. She further stated that the Companies should seek to minimize additions of new gas-fired combined cycle and combustion turbines to minimize risk to customers and avoid stranded costs, and that alternative portfolios of solar, wind, storage, and energy efficiency resources could also form the basis of Duke's electricity supply and avoid such stranded asset risks. (Tr. pp. 2152.5, 2152.23:10 – 2152.24:15.)

Commission Conclusions

The Commission agrees with the testimony of Witnesses Fitch and Lucas that the Companies' IRPs are inconsistent with Duke Energy's 2050 net-zero carbon goal and that the 2020 IRPs do not adequately address climate risks, including potential stranded asset risks to ratepayers.

The Commission is concerned that the Companies' 2020 IRPs do not adequately consider the regulatory risks of carbon policies that are likely in the future; the Commission is also concerned that the Companies' 2020 IRPs appear to be inconsistent with Duke Energy's 2050 net-zero carbon goal, which could have negative impacts on South Carolina ratepayers due to stranded asset costs.

As discussed in other sections of this Order, the Commission is requiring the Companies to revise several assumptions in their 2020 IRPs that will help to mitigate these climate-related regulatory and stranded asset risks. However, the Commission believes a more robust assessment of these risks is necessary in future IRP filings. Therefore, the Companies are directed to include in all future IRPs and IRP updates a systematic assessment of climate-related risks to the operating company, including but not limited to physical risks, financial risks, economic risks, and regulatory risks. The Companies shall also explicitly include an evaluation of potential stranded asset risks to ratepayers associated with the deployment of carbon-emitting resources in light of the Companies' 2050 net zero goal and potential future carbon regulations.

2. The Synapse Report

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 27

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony and exhibits of Dewey S. "Sammy" Roberts, Glen Snider and Rachel Wilson, and the entire record in these proceedings.

Witness Snider testified on rebuttal that the intervenors' agendas "do not include pursuing least cost planning and ensuring power supply reliability to meet load . . . ." (Tr. p. 1586.21:11-13.) According to Mr. Snider, the Companies "strongly support the further development of solar resources, battery storage and DSM/EE programs" but the intervenors' "singular focus on increasing the deployment of these resources often omits the key considerations of system reliability and affordability." (Tr. p. 1586.22:18-21.)

Witness R. Wilson's surrebuttal testimony responded to Witness Snider's assertions, summarizing the results of an analysis by her firm Synapse Energy Economics, which were detailed in a report entitled "Clean, Affordable, Reliable: A Plan for Duke Energy's Future in the Carolinas" (the "Synapse Report"). (H.E. 56 [Ex. RSW-2].) The Synapse Report used the EnCompass model to select the optimal, least-cost capacity mix to meet Duke's peak and annual energy requirements at the lowest cost over time. (Tr. p. 2151.7:7-8; H.E. 56 [Ex. RSW-2].) Synapse chose EnCompass because it is a widely accepted model with capacity expansion and production cost capability, and because Duke is transitioning to the use of EnCompass for resource planning. (Tr. pp. 2151.14:12 – 2151.15:2.) As explained in the Synapse Report, "the model does the following: (1) builds new resources when necessary to meet peak demand, plus a required reserve margin; (2) simulates economic dispatch of the various generating resource; and (3) calculates the total cost (capital and operating) of the respective resource portfolio options." (H.E. 56 [Ex. RSW-2 p. 11].)

According to Witness R. Wilson, Synapse used the EnCompass model to develop two scenarios. In the first, called "Mimic Duke," Synapse primarily used Duke's own assumptions to create a resource portfolio that results in a similar, but not identical, portfolio to Duke's Base Case With Carbon Policy. (Tr. p. 2151.16:4-7.) The Mimic Duke scenario includes 8.8 GW of new gas-fired combined cycle and combustion turbine units, with 3.4 GW of solar PV additions. (Tr. p. 2151.19:5-7.)

For the second scenario, "Reasonable Assumptions," Synapse modified the model to reflect some assumptions which Witness R. Wilson contended were more robust and defensible. (Tr. p. 2151.17:5-6.) In particular, Synapse increased the forecasted energy efficiency in Duke's service territories such that first year program savings increase by 0.15 percent of retail sales per year beginning in 2022, until they reach 1.5 percent, and then stay at this level through the planning horizon. (Tr. p. 2151.17:6-10.) The Reasonable Assumptions scenario used Duke's "Earliest Practicable" coal retirement dates. (Tr. p. 2151.17:10-11.) Synapse also used capital costs for wind and battery resources, and operations and maintenance ("O&M") costs for solar, from the National Renewable Laboratory's 2020 Advanced Technology Baseline. (Tr. pp. 2151.17:12 – 2151.18:2.) To allow the model to choose resources based primarily on their energy benefit to the system rather than on the capacity need each year, the costs of wind and solar resources were levelized using Duke's assumptions regarding the weighted average cost of capital and construction schedule for the different resources, and offered to the EnCompass model on a $/MWh basis. (Tr. p. 2151.18:2-7.) The Reasonable Assumptions scenario also restricted new gas additions, to account for the likelihood that any new gas additions would need to be retired before they are fully depreciated. (Tr. p. 2151.18:7-9.) Other assumptions, including the 17 percent planning reserve margin and the ELCC of renewables and storage, were left unchanged. (Tr. p. 2151.22:5-9.) A comparison of the assumptions in the two Synapse scenarios is shown in Ms. Wilson's Table 2. (Tr. p. 2151.17:3.)

Under the Reasonable Assumptions scenario, the model selected a portfolio that retires Duke's coal units and adds 16 gigawatts (GW) of new utility-scale solar, 2.5 GW of new onshore wind, and 10 GW of new battery storage by 2035. (Tr. p. 2151.7:3-7.) The Reasonable Assumptions portfolio, with a net present value of revenue requirements ("NPVRR") of $68.5 billion, also reduces total system cost by $7.2 billion relative to the Mimic Duke portfolio, whose NPVRR is $75.6 billion. (Tr. p. 2151.20:10-14.) According to Witness R. Wilson, the Synapse Report shows that a resource portfolio that accelerates coal retirements, restricts new gas additions and maximizes clean energy resources can maintain reliability while minimizing costs to ratepayers. (Tr. p. 2151.6:3-8; H.E.56.)

Through cross-examination of Witness R. Wilson and supplemental testimony of Witness Roberts, Duke counsel elicited testimony on several points where Duke contended that simplifications or errors were made in developing the Synapse Report. Ms. Wilson provided responsive testimony on each of these points.

First, Witness Roberts critiqued Table 2 of the Synapse Report, which showed the low annualized capacity factors for Duke's coal fleet, and testified that most units had 90 to 100 percent capacity factors during the week of January 2-8, 2018. (Tr. p. 1058:4-16; H.E. 31 [Roberts Direct Ex. 2].)Witness R. Wilson responded that the January 2018 week referred to by Mr. Roberts was an unusually cold winter week, and that Roberts Direct Ex. 2 did not show that Duke needs to keep its coal units online to meet load during an extreme winter weather event. (Tr. p. 2154:9-24.) Ms. Wilson explained that the exhibit presented limited information about the operation of the DEC and DEP system during that week, and that since that time, Duke has added nearly 1,000 MW of gas capacity. (Tr. pp. 2155:1-2156:15.)

Second, Synapse modeled the DEC, DEP-East and DEP-West balancing authority areas ("BAs") as a single BA for purposes of the analysis. (Tr. p. 2211:4-5.) Witness R. Wilson testified that Synapse made the decision to model the three BAs as a single BA because Duke dispatches its units over the combined DEC and DEP service territory, and there are benefits to modeling the combined BAs that way in terms of providing the lowest-cost generation option in a given hour on the system. (Tr. p. 2283:9-17.) Ms. Wilson further testified that because Synapse did this for both the "Mimic Duke" and "Reasonable Assumptions" portfolios, the resulting resource builds or costs would be adjusted in a similar way. (Tr. p. 2212:1-6.)

Third, Witness R. Wilson acknowledged that the Synapse Report had erroneously assumed that the Catawba Nuclear Units 1 and 2 were 100 percent Duke-owned, rather than owned jointly with other utilities. (Tr. p. 2220:14-20.) Ms. Wilson pointed out that the ownership percentage was assumed to be 100 percent for both the Mimic Duke and Reasonable Assumptions scenarios. (Tr. pp. 2220:24 – 2221:2.) Ms. Wilson further explained that if the two scenarios are changed in a similar way, the delta (difference) between the present value of revenue requirements is maintained between those two scenarios. (Tr. p. 2225:15-17.)

Fourth, Witness Roberts critiqued the load shape presented in Figure 5 of the Synapse Report, which showed a projected load shape in January 2030, as not representative of the Companies' future load shape. (Tr. p. 1064:11-16.) Mr. Roberts presented and described an exhibit comparing the Synapse load shape (depicted as an orange line) with Duke's load shape from January 5, 2018 (depicted as a blue line). (Tr. p. 1063:1-10; H.E. 31 [Roberts Direct Ex. 4].) With regard to the load shape critiqued by Mr. Roberts, Witness R. Wilson explained that Synapse took the load shape that was produced by Duke, and then input it into the EnCompass model, which applied an algorithm to be able to simulate the peak day represented in Figure 5 of the Synapse Report. (Tr. p. 2240:15-20.) The load shape produced by Duke was not compatible with EnCompass in a way that would allow the model to produce the "blue line" load shape. (Tr. p. 2240:21-24.) Ms. Wilson acknowledged that it would take more energy to serve the load depicted in the "blue line" than the "orange line." (Tr. p. 2243:16-20.) However, Ms. Wilson explained that in the Reasonable Assumptions modeling, the existing gas resources are not generating at maximum output during the "shoulder" hours in the morning and evening, and can therefore produce more energy in those hours to meet the load shape shown in the blue line. (Tr. p. 2167:9-17.) Moreover, both the Mimic Duke and Reasonable Assumptions scenarios employed a load shape similar to that depicted in the orange line, "so if there was a need to add resources, you would need to add them in both scenarios. And so you're adding cost to both, and still the important thing to consider is the delta between those scenarios." (Tr. p. 2244:1-8.)

Finally, Witness R. Wilson agreed that in certain years of the Synapse modeling, the reserve margin dipped below the 17 percent planning reserve margin. (Tr. p. 2251:8-13.) Ms. Wilson explained that this was because the EnCompass model employs a "capacity penalty" in instances when there is a capacity deficit on the utility's system in order to meet the reserve margin. (Tr. pp. 2251:13 – 2252:3.) The capacity penalty is a proxy for a short-term power purchase agreement and is factored into the revenue requirement. (Tr. p. 2252:11-18.)

Witness R. Wilson testified that she was not asking the Commission to adopt the Synapse Reasonable Assumptions portfolio as Duke's resource plan, but rather,

> [T]he Synapse report is illustrative. It shows how a clean, low carbon plan can also be least cost. It doesn't purport to be the alternate resource plan that Duke must follow. But instead it shows that a clean, low cost portfolio can meet customer needs at a lower cost than what Duke has modeled. And the Clean Energy Intervenors are not asking the Commission to adopt this portfolio, but instead . . . I'm just recommending that the Commission require the companies to update their modeling with the correct data and inputs that are used in the Reasonable Assumptions scenario.

(Tr. pp. 2177:14 – 2178:21.) Accordingly, Ms. Wilson recommended that the Commission reject the DEC and DEP 2020 IRPs and require the Companies to update their modeling and file modified IRPs within 60 days of the Commission's order. (Tr. pp. 2151.7:19 – 2151.8:2.)

Commission Conclusions

The Commission concludes that the Synapse Report and Witness R. Wilson's testimony, taken together with the testimony and exhibits of other witnesses in this proceeding and viewed in the context of the whole record, demonstrate that a resource portfolio that accelerates coal retirements, restricts new gas additions, and maximizes energy efficiency, renewables and storage can maintain reliability while minimizing costs to ratepayers.

The Commission is not persuaded by the critiques of the Synapse Report mounted by Duke Witnesses Roberts and Snider, to which Witness R. Wilson's testimony responded point by point. Notably, Ms. Wilson testified that the Synapse Report was illustrative, and that she was not asking the Commission to adopt the Synapse Reasonable Assumptions portfolio as Duke's resource plan. Her recommendation was much more modest: that the Commission require the Companies to update their own modeling with the data and inputs that are used in the Reasonable Assumptions scenario. This recommendation was consistent with Act 62's requirement that the utility file resource portfolios "developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations." S.C. Code Ann. § 58-37-40(B)(1)(e).

This Commission has an obligation to approve a utility IRP that it finds "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." S.C. Code Ann. §58-37-40(C)(2). In light of the evidence showing that the Reasonable Assumptions portfolio resulted in a lower-cost, lower-risk plan than any of the portfolios presented in Duke's IRPs, the Commission is unable to conclude that Duke's IRPs include the "most reasonable and prudent plan." Regardless of the intent of the Synapse Report, it suggests strongly that adjusting Duke's modeling assumptions similarly will produce results which would certainly be instructive as to which plan could be considered most reasonable and prudent. It is therefore reasonable for this Commission to require the Companies to model a scenario that employs the assumptions used in Synapse's Reasonable Assumptions scenario, and to include the results in modified IRPs to be filed within 60 days of the Commission's order in these proceedings.

3. All Source Procurement

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDING OF FACT NO. 28

Summary of the Evidence

The evidence in support of these findings of fact is found in the Proposed IRPs, pleadings, testimony of ORS Witness Anthony Sandonato, CCEBA Witnesses Kevin Lucas and Arne Olson, Duke Witnesses Glen Snider, Matthew Kalemba, and Nick Wintermantel, and CCL et al. Witness John Wilson, as well as their exhibits, and the entire record in these proceedings.

The testimony and exhibits of several witnesses in these proceedings revealed numerous disputed issues regarding the cost and availability of different resources. For example, the ORS Reports sponsored by ORS Witness Anthony Sandonato stated that capital costs used in the IRPs for natural gas-fired combustion turbine units are lower than other publicly available estimates. (H.E. 24 [Ex. AMS-1 ("ORS DEC Report") p. 72; Ex. AMS-2 ("ORS DEP Report") p. 71].) The ORS Reports further stated that models failed to include post-in-service capital costs for new resource additions. (H.E. 24 [ORS DEC Report p. 87; ORS DEP Report p. 86].) Duke Witness Glen Snider countered that Duke's models did include post-in-service capital costs for new resource additions. (Tr. p. 1586.147.)

The ORS Reports stated that ORS was concerned that the IRPs did not discuss how the actual inputs into the company's resource expansion plan modeling were derived from reported capacity value results. (H.E. 24 [ORS DEC Report p. 40; ORS DEP Report p. 40].) The ORS Report stated that the stand-alone solar capacity values presented in the 2018 Astrapé ELCC study as part of the avoided cost proceeding were reported for various levels of solar capacity, whereas for IRP planning purposes a single one percent capacity value assumption was used for all assumed levels of solar capacity on the system. (H.E. 24

[ORS DEC Report p. 40; ORS DEP Report pp. 40–41].) Duke Witness Matthew Kalemba, on the other hand, testified that the winter peak capacity value of approximately one percent of nameplate capacity for solar was reasonable. (Tr. pp. 1390.34 – 1390.35.)

With regard to solar cost assumptions, the ORS Reports recommended that Duke Energy include an additional solar generic resource option in its IRP modeling that reflects the kind of solar PPA prices that may be available in the market, referencing an average price of $38/MWh under competitive solicitation. (H.E. 24 [ORS DEC Report p. 73; ORS DEP Report p. 72].). Witness Sandonato stated that Duke Energy's levelized cost of energy ("LCOE") for solar is higher than other publicly available estimates. *Id.* Witness Kalemba disagreed with the ORS analysis of LCOE values, stating that the values shown by ORS are inconsistent and not accurate for the Carolinas. (Tr. p. 1390.11.) Witness Lucas testified that the federal investment tax credit extension could reduce levelized costs of solar projects by $3-4/MWh. (Tr. p. 501.38.) Mr. Kalemba countered that the extension of the federal investment tax credit occurred after the IRP was developed, and that the inputs were fixed, but that the ITC will be included in the 2021 update. (Tr. pp. 1390.7 – 1390.8.) Mr. Lucas stated that although the solar capital cost forecast was reasonable, the industry has often seen costs come down more quickly than anticipated. (Tr. p. 501.40.) Mr. Lucas noted that solar operations and maintenance costs should be discounted to reflect regionally lower costs and include a declining forecast. (Tr. p. 501.41.) Witness Snider testified that it is not possible to know the cost of a solar facility over its full useful life. (Tr. pp. 1586.122 – 1586.123.)

Witness Lucas testified that existing fixed-tilt solar projects will often be replaced by tracking systems. (Tr. p. 501.58.) CCEBA Witness Arne Olson stated that tracking solar generally generates more electricity than fixed-tilt solar, and also tends to have higher production during the late afternoon when loss-of-load events are most likely to occur. (Tr. pp. 485.25 – 26.) Witness Olson also criticized the the assumption in Astrapé's Solar ELCC study that 40% of future solar will be fixed-tilt and 60% of future solar will be single axis tracking as inappropriate because technological advancements and cost decreases in tracking systems will result in very few fixed-tilt systems being installed in the future. (Tr. p. 485.26.) Witness Kalemba testified in rebuttal that the assumption that all PURPA facilities that are currently fixed-tilt solar will be replaced with fixed-tilt solar in the future was reasonable because Duke Energy does not expect them to change to tracking. (Tr. p. 1390.32.) He further stated that it is reasonable to assume that solar added under the Competitive Procurement of Renewable Energy ("CPRE") program will be 60% fixed-tilt and 40% tracking because that represented the division in CPRE bids at the time Duke Energy developed its IRPs. (Tr. p. 1390.33.) He clarified that Duke Energy assumed a 50-50 blend of fixed-tilt and single-access tracking solar for the purpose of calculating reserve margins and the winter peak capacity value of solar, transitioning to a 60-40 blend after 2025. (Tr. pp. 1390.33 – 1390.34.)

With regard to storage assumptions, the ORS Reports also concluded that the capacity factor assumptions for storage should be investigated further. (H.E. 24 [ORS DEC Report pp.73 – 74; ORS DEP Report pp. 72 – 73].) The ORS Reports stated that Duke's capital cost assumption for battery energy storage appears to be at the high end of estimates and that battery storage operation and maintenance costs are not in line with other estimates. (H.E. 24 [ORS DEC Report pp.72 – 73; ORS DEP Report pp. 71 – 72].) Witness Kalemba testified that battery storage costs are uncertain and difficult to rely on for planning purposes, (Tr. pp. 1390.15– 1390.16, 1390.21, 1390.25) and that battery storage operations and maintenance cost assumptions will be corrected in the 2021 update. (Tr. p. 1390.28.) Witness Lucas testified that Duke Energy's approach to battery degradation in solar plus storage projects greatly exaggerates the cost of storage. (Tr. p. 501.46.) Witness Olson testified that system operators have the ability to forecast winter peaking events in time to fully charge and then dispatch battery storage. (Tr. p. 485.25.) Mr. Olson testified that Duke Energy modeled storage in a way that does not capture the maximum value, and that the Companies could update their ELCC study to model storage resources in "preserve reliability" mode. (Tr. pp. 485.24 – 485.25.) Mr. Kalemba disagreed with Mr. Olson, stating that modeling storage resources on a "preserve reliability" basis would not be appropriate because battery storage will be deployed to provide all possible value streams, including "economic arbitrage." (Tr. p. 1390.40.)

In rebuttal, Witness Snider agreed that Witness Olson was correct that adding demand response capacity in the winter would move LOLE to the summer, increasing the capacity value of solar. (Tr. p. 1586.130.) However, Mr. Snider countered that as part of the 2020 Resource Adequacy Study, Astrapé modeled increased winter demand response potential and there was no material shift of risk to the summer, and further that Duke Energy still would be a winter-planning utility and the capacity value of solar would remain small. *Id.* Mr. Snider testified that although Duke Energy evaluated the economic impact of batteries after the capacity expansion model selected replacement resources, batteries still were robustly evaluated in the production cost model. (Tr. p. 1586.132.) Mr. Snider also stated that the capacity factor assumption for battery storage is appropriate. (Tr. p. 1586.120.) Duke Energy Witness Nick Wintermantel agreed with Mr. Olson that storage and solar have synergistic values, but stated that this was already accounted for in the Storage ELCC Study. (Tr. p. 389.34.) Witness Wintermantel testified that Astrapé views E3's ELCC for stand-alone storage as exceptionally low. (Tr. p. 389.35.)

CCL et al. Witness John D. Wilson, Research Director of Resource Insight, Inc., testified in surrebuttal to the rebuttal testimony of Witnesses Snider, Kalemba, and Wintermantel. Witness Wilson testified that the resource planning process advocated by the Duke witnesses will lead to single-source procurements that will be conducted based on already obsolete assumptions (Tr. p. 2094:12-17) and that this approach will not lead to least-cost procurement (H.E. 53 [Ex. JDW-2, Carolinas ASP Report p. 2]). He summarized the disputes discussed above regarding resource assumptions in a table in his testimony. (Tr. pp. 2098.13 – 2098.15.)

Witness Wilson then testified that an alternative all-source procurement approach to procuring new resources would resolve many of the technical arguments mounted in the Duke witnesses' rebuttal testimony in response to ORS and intervenor witnesses. (Tr. p. 2094:17-21.) According to Mr. Wilson, shifting to an all-source procurement approach will result in the least cost to procure the portfolio being solicited. (Tr. p. 2120:19-25.) He recommended that the Commission require Duke Energy to conduct all-source procurement according to a process set out in his testimony. (H.E. 53 [Ex. JDW-2, Carolinas ASP Report pp. 19 – 20]) Mr. Wilson further recommended that the Commission require DEC and DEP to begin using an all-source procurement process to meet system needs in 2026 and beyond, because most resources identified in the short-term action plans are approved or otherwise committed for construction or procurement. (H.E. 53 [Ex. JDW-2, Carolinas ASP Report pp. 4 – 7].)

Briefly, the process Witness Wilson recommended involves two steps. First, DEC and DEP would define their need for new resources, in terms of the load forecasts that need to be met, evolving system operating requirements, and existing plants that may need to be retired. (H.E. 53 [Ex. JDW-2, Carolinas ASP Report p. 19].) Second, each utility would solicit bids to meet its total system need for the entire 2026 to 2031 time period, in a unified resource acquisition process in which the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market, evaluating and contracting in a staged all-source RFP process. (H.E. 53 [Ex. JDW-2, Carolinas ASP Report pp. 4, 20].)

Commission Conclusions

The evidence showed that in developing its IRPs, DEC and DEP employed an approach to procuring new resources that relies on cost forecasts and other assumptions that necessarily will be outdated at the time of actual procurement, and that this approach likely will lead to unnecessarily costly single-source procurement of resources. The Commission credits the testimony of Witness Wilson in identifying the issue and proposing a comprehensive solution. Meeting total system needs through a technology-neutral, all-source procurement process will better ensure that the DEC and DEP procure the least-cost resource mix, enhancing ratepayer savings and value. Future Duke Energy IRPs should recommend a portfolio of resources that best meets the needs of the DEC and DEP systems using actual bid data. Accordingly, the Commission concludes that it is reasonable to require Duke Energy to adopt and implement an All Source Procurement Plan in its 2022 IRPs, for procurement in 2026 and following years.

VI. ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. In future IRPS, the Companies must prepare additional load forecast scenarios, such as high and low scenarios that account for economic and other types of uncertainty. In addition, the level of uncertainty evaluated in the future load forecast analyses used to develop IRPs should be consistent with the Companies' resource adequacy studies.

2. The Companies are required to use the UCT when developing EE/DSM scenarios and savings projections in its future IRPs, IRP updates, and market potential studies.

3. To correct for the Companies' use of the TRC in the 2020 IRPs, the Companies shall in the modified IRPs apply a 10% increase to the achievable potential in the Base scenario when developing the Base DSM/EE projections in the IRPs, as the Companies have already done for the Enhanced scenario and corresponding High EE/DSM projections. Because the Low EE/DSM projections are based on the Base EE/DSM projections, the 10% increase should apply to the Low EE/DSM projections as well.

4. In future IRPs, IRP updates, and market potential studies, the Companies must work with the EE/DSM Collaborative to identify a set of reasonable assumptions surrounding 1) increased market acceptance of existing technologies and 2) emerging technologies to incorporate into EE/DSM saving forecasts. The Companies should also work with members of the Collaborative to ensure that residential saving projections are not overly dependent on behavioral programs with short savings persistence. Further, the Companies' next IRPs should identify which of the Collaborative's recommendations relating to market acceptance, emerging technologies, and types of programs were and were not adopted when developing market potential studies and IRPs.

5. In future IRPs, the Companies must evaluate high and low EE/DSM cases across a range of fuel and CO_2 assumptions to better understand what level of EE/DSM should be implemented if fuel costs rise or higher CO_2 costs are imposed.

6. The Companies must study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load for use in future IRP proceedings.

7. The Companies should prepare additional load forecast scenarios (such as high and low scenarios.), as required by South Carolina regulations. The Companies should also prepare forecasts of extreme or "90-10" summer and winter peak loads, that is, the peaks that are expected to occur only once in ten years.

8. The Companies should consider defining an alternative metric for expressing and communicating target reserve margins, which might use, in the numerator, an aggregate capacity value measure (reflecting load carrying capacity rather than installed capacity). An alternative metric might also use, in the denominator, a 90-10 extreme (rather than weather normal) forecast peak load value. Reserve margin targets defined in such terms, which could be presented together with traditional installed reserve margin measures, would be more robust and stable over time as load patterns and the capacity mix change.

9. Duke should make a number of changes to its development of effective load carrying capability ("ELCC") values and revisions to its capacity expansion modeling that incorporates those ELCC values, including:

  a. Applying single-step optimization rather than multi-step optimization when conducting its capacity expansion modeling;

b. Creating an ELCC "surface" that determines the combined capacity value of different portfolios of solar and storage;

c. Using the UCAP rather than ICAP method for calculating PRM;

d. Revising resource ELCC studies by:

   i. Varying ELCC as a function of load, including applying a 2035 load profile;

   ii. Modeling storage resources in preserve reliability mode to more accurately capture their highest value use during extreme peak load events;

   iii. Modeling all future solar as single-axis tracking consistent with industry trends; and

   iv. Updating DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment.

10. The Companies shall perform a comprehensive coal retirement analysis to inform development of their 2022 IRPs. This analysis shall evaluate, among other things, the costs of continued operation of DEC's and DEP's coal plants, as well as replacement options. The Companies shall solicit parties' recommendations on guidelines for performing this analysis via the ongoing IRP stakeholder process, and shall adopt a set of guidelines prior to development of the 2022 IRPs.

11. In its next Full IRP, Duke shall address the risks of natural gas transportation and delivery, including rejection of cancellation of pipeline projects; and shall quantitatively address the potential impacts of transport and delivery risk on natural gas availability and pricing.

12. In its next Full IRP, Duke shall account for the risk of non-available firm fuel for CT units during peak winter mornings and evenings when building heating load is highest.

13. In its Modified IRP, IRP Update, and future full IRPs, Duke shall remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts, as recommended by CCEBA Witness Lucas.

14. In its Modified IRP, IRP Update, and future full IRPs, Duke shall adjust its high and low-price scenarios to reflect the 25th and 75th percentile results to reduce price volatility.

15. In the Modified IRP and IRP Update, the Companies shall include third-party solar PPAs priced at $38/MWh as a selectable resource. Any change to this pricing in subsequent IRPs or IRP Updates shall be supported by a reasonable investigation into market conditions in Duke's service territories.

16. For purposes of modeling solar PPAs as a selectable resource, the Company shall assume a contract term of at least 20 years, and operational characteristics identical to CPRE projects.

17. Duke shall include sensitivities in the modified IRP for PPA pricing at $36/MWh and $40/MWh.

18. Duke is ordered to modify its IRP and adjust its IRP modeling to account for the effect of the December 2020 ITC extension on solar development.

19. Duke is ordered to adjust its modeling as suggested by witness Lucas to take into account the increasing market saturation of single-axis solar systems in the DEC and DEP territories.

20. In its Modified IRP and future IRPs, Duke shall use the NREL ATB Low figures for battery storage costs.

21. In its Modified IRP and next IRP Update, Duke shall assume a 750 MW annual limitation on the interconnection of solar and storage resources.

22. In its next full IRP, Duke shall, if it elects to impose a limitation on interconnections, provide a limitation that is analytically justified, nondiscriminatory, and accounts both for the expected benefits of queue reform and the possibility of making further investments in the Companies' capacity to study and interconnect new generation.

23. In future IRPs, including Modified IRPs and IRP Updates, Duke shall perform and include a minimax regret analysis of the type described and performed in this proceeding by CCEBA Witness Lucas.

24. The Companies are directed to include in all future IRPs and IRP updates a systematic assessment of climate-related risks to the operating company, including but not limited to physical risks, financial risks, economic risks, and regulatory risks. The Companies shall also explicitly include an evaluation of potential stranded asset risks to ratepayers associated with the deployment of carbon-emitting resources in light of the Companies' 2050 net zero goal and potential future carbon regulations.

25. DEC and DEP shall model a scenario that employs the assumptions used in Synapse's Reasonable Assumptions scenario, and shall include the results in modified IRPs to be filed within 60 days of the Commission's order in these proceedings.

26. DEC and DEP shall develop plans to implement all-source procurement to meet system needs, pursuant to the approach described in Exhibit JDW-2 to CCL et al. Witness John Wilson's surrebuttal testimony (H.E. 53) and shall include such plans in their 2022

and later IRPs and IRP Updates. In developing such plans, DEC and DEP shall plan for implementation of all-source procurement beginning in 2026.

BY ORDER OF THE COMMISSION:

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Respectfully submitted,

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BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Progress, LLC	)))))))))))	**CERTIFICATE OF SERVICE**

I hereby certify that the parties listed below have been served via electronic mail with a copy of the *Proposed Order* on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Sierra Club, Upstate Forever, and Natural Resources Defense Council, and the Carolinas Clean Energy Business Association.

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This 9th day of June, 2021.

/s/ Kate Mixson